March 13, 2009

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Subject: Docket No. 2008-0273
Feed-In Tariffs Investigation
Information Request Responses

Pursuant to the Order Approving the HECO Companies' Proposed Procedural Order, as Modified, filed on January 20, 2009, attached are Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), Maui Electric Company, Limited ("MECO") (collectively, the "HECO Companies") and the Division of Consumer Advocacy's ("Consumer Advocate") joint responses to the information requests submitted March 4, 2009, by the following parties[1] in the above proceeding:

- Blue Planet Foundation
- The Department of Business, Economic Development, and Tourism
- Hawaii Renewable Energy Alliance
- Alexander & Baldwin, Inc. through its division, Hawaiian Commercial & Sugar Company
- The Solar Alliance
- Tawhiri Power LLC
- Zero Emissions Leasing LLC

Sincerely,

for Catherine P. Awakuni
Executive Director
Division of Consumer Advocacy

for Darcy Endo-Omoto
Vice President
Hawaiian Electric Company, Inc.
Hawaii Electric Light Company, Inc.
Maui Electric Company, Limited

Attachments

cc: Service List

[1] The following parties did not submit information requests: City and County of Honolulu, County of Hawaii, Clean Energy Maui LLC, Haiku Design and Analysis, Hawaii Holdings, LLC, doing business as First Wind Hawaii, Hawaii BioEnergy, LLC, Hawaii Solar Energy Association, Life of the Land, Maui Land and Pineapple Company, Inc., Sempra Generation, and Sopogy Inc..

SERVICE LIST
(Docket No. 2008-0273)

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Blue Planet Foundation

BP-IR-1

As set forth in the Energy Agreement, the HECO Companies and Consumer Advocate:

- State that they believe "[t]he future of Hawaii requires that we move more decisively and irreversibly away from imported fossil fuel for electricity and transportation and towards indigenously produced renewable energy and an ethic of energy efficiency. Id. (emphasis added).

- State that "[t]he very future of our land, our economy and our quality of life is at risk if we do not make this move and we do so for the future of Hawaii and of the generations to come." Id. (emphasis added).

- Commit to "a system of utility regulation that will transform our major utility from a traditional sales-based company to an energy services provider that . . . moves us to an energy independent future." Id. (emphasis added).

- Commit to integrate "the maximum attainable amount of wind energy on their systems." Id. at 3 (emphasis added).

- *Agree that the HECO Companies "are responsible for expeditiously integrating* customer-sited PV and CSP energy into the utility system[.]" Id. at 12 (emphasis added).

- Agree to "implement feed-in tariffs as a method for accelerating the acquisition of renewable energy[.]" Id. at 17 (emphasis added).

- Commit to the goal of "70 percent clean, renewable energy for electricity and transportation by 2030[.]" Id. at 18 (emphasis added).

- Commit to "accelerate the adoption of" distributed generation and distributed energy storage. *Id.* at 27 (emphasis added).

a. Please identify the criteria, factors, and/or metrics You have employed, employ, or intend to employ, to measure, evaluate and/or determine the degree to which the Joint Proposal and HECO/CA Straw Tariff will or will not achieve the above-referenced Energy Agreement objectives ("Energy Agreement Objectives").

b. Please provide all documents and information related to Your measurement, evaluation, and/or determination of the degree to which the Joint Proposal and HECO/CA Straw Tariff will or will not achieve the Energy Agreement Objectives.

Response:

a. Section 7 of the Hawaii Clean Energy Initiative Energy Agreement states that, "[u]tility purchases of renewable energy under the feed-in tariff shall be counted toward the utility's Renewable Portfolio Standard requirements;" Thus, one significant quantitative measure of the contribution of a feed-in tariff in achieving objectives of the Energy Agreement is the portion of the utility's RPS attributable to kilowatthours generated from renewable generators contracted through a feed-in tariff at each milestone year of the RPS law (i.e., 2010, 2015, 2020) and the 2030 RPS milestone in the Energy Agreement. Other Energy Agreement Objectives are qualitative and thus not measurable through a series of quantifiable metrics.

It should be noted that a feed-in tariff program is just one of many programs or resources agreed to in the Energy Agreement envisioned to contribute to the ambitious goal of increasing levels of clean energy to 70% and is not envisioned to be the sole resource or program needed to achieve such clean energy goals. The real value of a feed-in tariff program, as stated in the Energy Agreement is to, "provide predictability and certainty with respect to the future prices to be paid for renewable energy and how much of such energy the utility will acquire." At this time, the Companies do not have any specific plans to establish a criteria, factors or metrics to measure or quantify the efficacy of an adopted feed-in tariff program in achieving this stated value. However, the Companies do believe that its proposed feed-in tariff proposal does provide predictability and certainty with respect to the future prices to be paid for renewable energy and how much energy the utility will acquire from projects contracted through a feed-in tariff program.

b. Please see our response to subpart a above.

BP-IR-2

The Joint Proposal proposes an interim design followed by regular updates ("Interim FIT"). Joint Proposal at 8-11. Please provide all documents and information related to Your measurement, evaluation, and/or determination of the degree to which the Interim FIT will or will not achieve the Energy Agreement Objectives.

Response:

By "Energy Agreement Objectives," the HECO Companies assume this to refer to the broad objectives described in the preamble to the Hawaii Clean Energy Initiative Agreement ("HCEI Agreement"). The preamble sets forth the overall objective that Hawaii "move more decisively and irreversibly away from imported fossil fuel for electricity and transportation and towards indigenously produced renewable energy and an ethic of energy efficiency." Contained within the HCEI Agreement are numerous initiatives and commitments that collectively achieve this objective, including the development of a feed-in tariff ("FIT") for new renewable energy resources. As explicitly described on page 17 of the HCEI Agreement:

- The parties will respectfully request that by March, 2009, the Commission will conclude an investigative proceeding to determine the best design for feed-in tariffs that support the Hawaii Clean Energy Initiative, considering such factors as categories of renewables, size or locational limits for projects qualifying for the feed-in tariff, how to manage and identify project development milestones relative to the queue of projects wishing to take the feed-in tariff terms, what annual limits should apply to the amount of renewables allowed to take the feed-in tariff terms, what factors to incorporate into the prices set for feed-in tariff payments, and the terms, conditions, and duration of the feed-in tariff that shall be offered to all qualifying renewable projects, and the continuing role of the Competitive Bidding Framework;
- In addition, the parties will respectfully request that by July, 2009, the Commission will adopt a set of feed-in tariffs and prices that implement the conclusions of the feed-in tariff investigation;

As required by the Commission's order initiating this FIT proceeding, the HECO Companies and Consumer Advocate filed a joint FIT proposal on December 23, 2008 addressing all of the factors identified in the HCEI Agreement. The proposal, including the proposal to establish an initial FIT that would be updated within two years and regularly thereafter, is consistent with the objectives of the HCEI Agreement. The degree to which the FIT would apply to various technologies, projects sizes, and other factors is to be determined in the course of this proceeding.

No other documents are available other than the HCEI Agreement and the December 23, 2008 Joint Proposal.

BP-IR-3

The Joint Proposal proposes the following initial project sizes ("Initial Project Sizes"):

"a. PV systems up to and including 500 kW in size on Oahu, PV systems up to and Including 250 kW on Maui and Hawaii Island, and PV systems up to and including 100 kW in size on Lanai and Molokai.

b. CSP systems up to and including 500 kW in size on Oahu, Maui, and Hawaii Island, and up to and including 100 kW on Lanai and Molokai.

c. In-line hydropower systems up to and including 100 kW in size on Oahu, Maui, Lanai, Molokai, and Hawaii Island.

d. Wind power systems up to and including 100 kW in size on Oahu, Maui, Lanai, Molokai, and Hawaii Island."

Joint Proposal at 9-10 (footnotes omitted) (emphasis added).

Please provide all documents and information related to Your measurement, evaluation, and/or determination of the degree to which the Initial Project Sizes will or will not achieve the Energy Agreement Objectives.

Response:

Please see the response to BP-IR-2.

BP-IR-4

The Joint Proposal proposes that upon adoption of a feed-in tariff no new applications for net energy metering will be accepted and expansion of net energy metering system capacity will not be allowed ("NEM Termination"). Joint Proposal at 15. Please provide all documents and information related to Your measurement, evaluation, and/or determination of the degree to which the NEM Termination will or will not achieve the Energy Agreement Objectives.

Response:

The HCEI Agreement states

> NEM currently provides an interim measure to encourage the installation of and pay for renewable energy generated from customer-sited systems, generally PV systems. The parties agree that NEM will be replaced with an appropriate feed-in tariff and new net metered installations shall be required to incorporate time-of-use metering equipment and, when time-of-use rates are implemented on a full scale basis in Hawaii or the applicable area, the net metered customer shall move to time of use net metering and sale of excess energy. (HCEI Agreement, page 28)

The HECO Companies believe the FIT as proposed by the Companies and the Consumer Advocate on December 23, 2008, is consistent with this provision of the HCEI Agreement.

BP-IR-5

The Joint Proposal proposes that upon adoption of a feed-in tariff the Competitive Bidding Framework will remain in place. Joint Proposal at 15. Please provide all documents and information related to Your measurement, evaluation, and/or determination of the degree to which the Competitive Bidding Framework remaining in place will or will not achieve the Energy Agreement Objectives.

Response:

Please see the response to BP-IR-2. The HCEI Agreement specifies development of a feed-in tariff ("FIT"), and that the Public Utilities Commission consider the continuing role of the Competitive Bidding Framework in a FIT investigative proceeding. The HECO Companies' FIT proposal specifies that FIT be established for smaller distributed energy resources, and that the Competitive Bidding Framework remain intact as the preferred mechanism to acquire larger renewable resources. The rationale for targeting distributed resources under a FIT, and specifically resources of certain sizes, was presented in Section 3.4.1.1 of the HECO Feed-In Tariff Program Plan filed on December 23, 2008. That same rationale, viewed conversely, sets forth the HECO Companies' reasoning as to why the Competitive Bidding Framework should continue to be used for the larger resources currently subject to the Framework.

BP-IR-6

HREA-HECO/CA-IR-3 proposes modifying the Competitive Bidding Framework to exempt projects of up to 20 MW in size. Your response filed February 11, 2009 to HREA-HECO/CA-IR-3 objects to that information request as being outside the scope of issues in the Feed-in Tariff Docket and states that the HECO Companies support the existing thresholds. The Statement of Issues set forth in the Procedural Order asks "what role do other methodologies for the utility to acquire renewable energy play . . . including . . . competitive bidding[.]" Procedural Order at 8. Please provide all documents and information related to Your measurement, evaluation, and/or determination of the degree to which modifying the Competitive Bidding Framework to exempt projects up to 20 MW in size will or will not achieve the Energy Agreement Objectives.

Response:

Please see the response to BP-IR-5.

BP-IR-7

The HECO/CA Straw Tariff, Appendix I, "Schedule FIT Agreement" states that the Schedule FIT Agreement "shall not be construed to constitute a 'take or pay' contract[.]" Id. at 1 ("Take or Pay Provision"). Please provide all documents and information related to Your measurement, evaluation, and/or determination of the degree to which the proposed Take or Pay Provision will or will not achieve the Energy Agreement Objectives.

Response:

The HCEI Agreement, in its preamble, states that the parties "will strive to assure that this process to achieve the HCEI goals and objectives will be directed towards providing ratepayer benefits, including long term price stability, and ultimately lower costs than would be incurred using imported fossil fuels." (HCEI Agreement, page 1) A Take or Pay Provision in a FIT energy purchase agreement would assign unreasonable financial risk to the utility and its customers. Thus, the HECO Companies' position that FIT power purchase agreements not be structured as Take or Pay contracts is in accordance with HCEI Agreement objectives.

No other documents are available other than the HCEI Agreement and the December 23, 2008 Joint Proposal.

Department of Business, Economic Development, and Tourism

DBEDT-IR-1-HECO/CA

Ref.: Joint Proposal.

(a) Please explain how the purchase power rates in HECO's planned PV Host Program will affect or be affected by the Feed-in Tariffs rates.
(b) Please explain how HECO will determine the purchase power rates for its planned PV Host Program, and whether or not the method and/or data will be different from the determination of the FiTs rates.

Response:

(a) It is presently anticipated that the PV Host Program energy payment rates will be established through an RFP bidding process with actual host sites identified in the RFP. It is contemplated that multiple sites will be consolidated and bid together within one RFP. Due to the economies of scale that can be realized by aggregating the sites, it is anticipated that the PV Host PPA energy rates may be less than the Feed-in tariff rates. The Feed-in tariff rates will be based on the cost of generation plus a reasonable rate of return.

(b) Please refer to response (a).

DBEDT-IR-2-HECO/CA

Ref.: Joint Proposal, Page 6.0

Please specify and describe the "complex financial accounting issues" relating to (1) type of fuel, (2) maturity of technology, (3) technology reliability, and (4) payment structure of purchased power contracts that have been addressed. Please explain how each of these "complex financial accounting issues" was addressed.

Response:

Long-term purchased power agreements impact the financial integrity of the Companies in one of three ways: 1) consolidation, 2) capital lease or 3) imputed debt. Consolidation and capital lease are accounting issues. All three (consolidation, capital lease, and imputed debt) are financial integrity issues.

Consolidation (See Attachment 1 for details.)

Consolidation accounting refers to the financial statement reporting treatment whereby the financial statements (i.e. income statement, balance sheet, and statement of cash flows) of one entity are put together with the financial statements of another entity and reported as if it were a single entity. In 2003, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 46 (revised), "Consolidation of Variable Interest Entities" ("FIN 46R"). It changed the criteria used to determine whether and how certain relationships should be reported on consolidated financial statements from an investment interest viewpoint to a more comprehensive financial interest viewpoint. The primary objective of FIN 46R is to provide guidance on the identification of, and financial reporting for, entities over which control is achieved through means other than voting rights. Entities meeting certain specific criteria are deemed "variable interest entities" ("VIE"). Projects which are developed in a separate legal entity are more likely to be determined to be variable interest entities. If an entity is determined to be a VIE, HECO must determine whether or not HECO is the "primary beneficiary". "Primary beneficiary" is the enterprise that will absorb a majority of the entity's expected losses, if they occur, or receive a majority of the entity's expected residual returns, if they occur, or both. The primary beneficiary must consolidate the VIE.

The consolidation of any significant independent power producer (new or existing) could have a material effect on HECO's consolidated financial statements, including the recognition of a significant amount of assets and liabilities. The debt of the seller will be shown as debt on HECO's balance sheet and the equity of the seller will be shown as minority interests. This will negatively impact HECO's financial ratios. Furthermore, if such a consolidated IPP were operating at a loss and had insufficient equity, the potential recognition of such losses could be cause for investor concern, thus increasing the Company's business risk.

Further, if consolidation under FIN 46R is required, HECO management must assess the IPP's internal controls over financial reporting in order to comply with section 404 of the Sarbanes-Oxley Act of 2002. The Company's independent certified public accountant ("CPA") must also certify management's internal control assessment process as well as perform its own testing of internal controls. HECO has publicly-traded securities registered with the SEC and must provide financial statements certified by a CPA in its registration statements filed with the SEC. The inability to provide certified financial statements (including attestation to internal controls) may result in SEC action against the Company.

As a result of the potential significant adverse financial consequences to the Company, HECO's position is that it will not enter into an agreement which it has determined may require HECO to consolidate the seller. Seller is required to demonstrate, with supporting information to allow HECO to verify such conclusion, that the proposal will not result in the seller under the power purchased agreement being a VIE that would trigger consolidation of seller's finances on HECO's balance sheet under FIN 46R. If HECO believes that the proposal may be subject to such treatment, it will inform seller and may request additional information or work with seller to structure the proposed power purchase agreement and/or the generation entity to avoid VIE treatment. If there is a change in circumstances during the term of the PPA that would trigger consolidation of seller's finances on to HECO's balance sheet, and such consolidation is not attributable to HECO's fault, then the parties will take all commercially reasonable steps, including modification of the PPA, to eliminate aspects of the arrangement that trigger consolidation, while preserving the economic "benefit of the bargain" to both parties.

Based on the contemplated pricing structure being fixed rate per KWH and not subject to adjustment based on the seller's costs, the draft Schedule FIT Agreement as proposed by the HECO Companies and Consumer Advocate for PV, CSP, inline hydro and wind is preliminarily not expected to result in requiring the Company to consolidate any entity for accounting and financial reporting.

Capital Lease (See Attachment 2 for details.)

For financial statement reporting purposes, a lease is defined as an agreement conveying the right to use property, plant, or equipment (land and/or depreciable assets) usually for a stated period of time. Lease accounting addresses the issue of how a lease is accounted for financial reporting purposes. There are at least two parties to a lease arrangement: lessor and lessee. Generally, operating leases are accounted for as expenses by the lessee while the lessor would report the investment in assets, related depreciation expense and lease revenue. On the other hand, if the agreement is deemed a capital lease, a lessee would report an investment in asset, related depreciation, a capital lease obligation and related interest expense. Capital lease obligations are considered a form of debt which would result in additional leverage being included in HECO's capital structure.

In order to determine the applicability of lease accounting to a PPA, it must first be determined whether the PPA is a lease. In May 2003, the Emerging Issues Task Force ("EITF") of the FASB issued EITF Issue No. 01-8 "Determining Whether an Arrangement Contains a Lease." EITF 01-8 specifies criteria under which service contracts, such as PPAs, are determined to be lease arrangements and subject to the requirements of Statement of Accounting Standards No. 13, "Accounting for Leases". If it is determined that a PPA is a lease, it must be determined to be either a capital lease or an operating lease. The primary source of accounting guidance as to whether a lease is a capital lease or an operating lease is Statement of Financial Accounting Standards No. 13 "Accounting for Leases" (FAS 13). A capital lease results in the net present value of the minimum lease payments being recorded as an asset and a liability on the purchaser's financial statements.

When a PPA is considered to be a capital lease in accordance with FAS 13, the net present value of the portion of energy purchase payments to be made by HECO to the IPP through the duration of the PPA term considered to be minimum lease payments must be presented as an asset and a liability on HECO's financial statements. This additional liability (debt) will negatively impact HECO's financial ratios. If a potential agreement is likely to be a capital lease, its implications on the debt ratio will be considered and the potential costs of utilizing the Company's debt capacity would be considered in the evaluation of the agreement's costs.

A preliminary evaluation of the HECO Companies' and Consumer Advocate's proposed Schedule FIT Agreement was performed and it appears that if payments under the Schedule FIT Agreement are fixed per KWH, the Agreement would not likely be determined to contain a lease.

The following items were key considerations in this evaluation: (a) the Company would not have the ability or right to operate the Customer-Generator facility, (b) the Company would not have the ability or right to control physical access to the Customer-Generator facility, and (c) the price paid by the Company for the output of the facility is contractually fixed per unit of output.

Different contract provisions may be prudent for different technologies, less mature technologies, and/or resources with different levels of reliability which may result in different accounting treatment.

Imputed Debt

"Imputed debt" (also referred to as "implied debt") refers to adjustments to the debt amounts reported on financial statements prepared under generally accepted accounting principles. Certain obligations do not meet the GAAP criteria of "debt", but have debt-like characteristics; therefore, credit rating agencies "impute debt and interest" in evaluating the financial ratios of a company. PPAs which are not capital lease obligations result in imputed debt. Credit rating agencies use different methods for calculating imputed debt. Standard & Poors ("S&P") has provided the most explicit explanation of its methodology for imputing debt, therefore the Company uses S&P's imputed debt methodology for evaluating the impact of PPAs.

Entering into a PPA with long-term fixed purchase power obligations would result in a higher debt ratio. This higher debt ratio could have a negative impact on how the investment community views HECO's risk profile. To the extent there is a negative impact on HECO and in its ability to secure financing at a reasonable cost, HECO would have to take mitigating action to reduce its own debt and infuse equity in order to rebalance its capital structure.

Financial Accounting Issues Addressed

Financial accounting issues have been addressed for existing purchased power agreements.

To date, wind, PV, CSP, and in-line hydro contracts have not resulted in consolidation or capital lease obligations being reflected on the utility's balance sheet. Contracts which have been evaluated under FIN 46R and EITF 01-8 include the following:

a) Wind

- Apollo Energy Corporation Restated and Amended Power Purchase contract ("Apollo RAC") (Docket No. 04-0346) – The Apollo RAC was not deemed to be a variable interest in Apollo because the RAC does not require HELCO to absorb variability of Apollo, and as such consolidation is not necessary. HELCO determined that the RAC is a capital lease; however, the payments meet the "contingent rentals" criteria and therefore are not considered minimum lease payments. Since there are no minimum lease payments, there is no lease asset and no lease obligation to record.
- Kaheawa Wind Power LLC (Docket No. 04-0365) – The Kaheawa PPA was deemed a variable interest and Kaheawa was deemed a variable interest entity; however, MECO was not deemed the primary beneficiary based on the information provided by Kaheawa. MECO determined that the Kaheawa PPA is a capital lease; however, the payments meet the "contingent rentals" criteria and therefore are not considered minimum lease payments. Since there are no minimum lease payments, there is no lease asset and no lease obligation to record.

b) The Sun

1) Photovoltaic

- Hoku Solar (Docket No. 2007-0425) – Based on information that was available to HECO at the time of the PUC application, HECO's preliminary determination was that FIN 46R would not be applicable due to the business scope exception of paragraph 4(h) of FIN 46R. Subsequently, HECO revised its assessment. HECO's revised assessment included an evaluation of risks associated with the PPA and determined that on a collective basis, the agreement creates variability in Hoku Solar; thus the PPA was not deemed a variable interest in Hoku Solar and therefore, HECO would not need to consolidate Hoku Solar. At the time of the PUC application, HECO made the preliminary assessment that the PPA was not a lease under EITF 01-8. Subsequently, HECO reassessed the PPA and determined that the PPA was a lease under EITF 01-8, and further determined that the arrangement was an operating lease under FAS 13.

- Lanai Sustainability Research (Docket No. 2008-0167) – The LSR PPA does not require MECO to absorb variability in LSR, therefore MECO would not have to consolidate LSR under FIN 46R. At the time of the PUC application, HECO made the preliminary assessment that the PPA was not a lease under EITF 01-8. Subsequently, HECO reassessed the PPA and determined that the PPA was a lease under EITF 01-8, and further determined that the arrangement was capital lease under FAS 13; however, the payments meet the "contingent rentals" criteria and therefore are not considered minimum lease payments. Since there are no minimum lease payments, there is no lease asset and no lease obligation to record.

2) Concentrated Solar Power

- Keahole Solar Power (Docket No. 2008-0186) -- The Keahole Solar PPA does not require HELCO to absorb variability in Keahole Solar, therefore HELCO would not have to consolidate Keahole Solar under FIN 46R. The PPA was deemed a lease under EITF 01-8, and further the arrangement was deemed an operating lease under

FAS 13.

c) Falling Water

- Makila Hydro, LLC (Docket No. 05-0161) – Based on the information available to MECO, it appears that MECO does not hold a variable interest in Makila and it appears Makila is not a variable interest entity within the scope of FIN 46R, therefore MECO is not required to consolidate Makila. MECO determined that the PPA was a lease under EITF 01-8, and further determined that the arrangement may be a capital lease under FAS 13; however, the payments meet the "contingent rentals" criteria and therefore are not considered minimum lease payments. Since there are no minimum lease payments, there is no lease asset and no lease obligation to record.

d) Biogas, including landfill and sewage-based digester gas – No contracts have been evaluated.

e) Geothermal – No contracts have been evaluated under current accounting standards. (See further discussion below regarding contracts in existence prior to 2003.)

f) Ocean water, currents, and waves – No contracts have been evaluated.

g) Biomass, including biomass crops, agricultural and animal residues and wastes and municipal solid waste

- Tradewinds – Based on the information currently available to HELCO, it appears that the business scope exception of paragraph 4 (h) of FIN 46R applies to Tradewinds, and therefore FIN 46R would not be applicable. The Tradewinds PPA is not deemed a lease under EITF 01-8 because it does not meet any of the conditions of control. The fact that the facility will be used in the milling operations is significant in determining that the arrangement is not a lease.

(See further discussion below regarding contracts in existence prior to 2003.)

h) Biofuels – No contracts have been evaluated.

i) Hydrogen produced from renewable sources – No contracts have been evaluated.

Contracts in Existence Prior to 2003

An enterprise with an interest in a variable interest entity or potential variable interest entity created before December 31, 2003, is not required to apply FIN46R to that entity if the enterprise, after making an exhaustive effort, is unable to obtain the information necessary to (1) determine whether the entity is a variable interest entity, (2) determine whether the enterprise is the variable interest entity's primary beneficiary, or (3) perform the accounting required to consolidate the variable interest entity for which it is determined to be the primary beneficiary. The scope exception in this provision applies only as long as the reporting enterprise continues to be unable to obtain the necessary information. Further, any modifications or amendments to contracts must be evaluated.

EITF 01-8 applies to (a) arrangements agreed to or committed to, if earlier, after the beginning of an entity's next reporting period beginning after May 28, 2003, (b) arrangements modified after the beginning of an entity's next reporting period beginning after May 28, 2003, and (c) arrangements acquired in business combinations initiated after the beginning of an entity's next reporting period beginning after May 28, 2003.

Consolidation

Consolidation accounting refers to the financial statement reporting treatment whereby the financial statements (i.e. income statement, balance sheet, and statement of cash flows) of one entity are put together with the financial statements of another entity and reported as if it were a single entity. Prior to 2003, the primary source of accounting guidance on the subject of when entities should be consolidated for financial reporting purposes was Accounting Research Bulletin No. 51, "Consolidated Financial Statements" ("ARB 51"). ARB 51 had required that an enterprise's consolidated financial statements include subsidiaries in which the enterprise had a controlling financial interest. The requirement usually had been applied to subsidiaries in which the enterprise had a majority voting interest.

In January 2003, the Financial Accounting Standards Board ("FASB")[1] issued FASB Interpretation No. 46, "Consolidation of Variable Interest Entities" ("FIN 46"). FIN 46 was an interpretation of ARB 51. FIN 46 changed the criteria used to determine whether and how certain relationships should be reported on consolidated financial statements. The primary objective of FIN 46 was to provide guidance on the identification of, and financial reporting for, entities over which control was achieved through means other than voting rights. "Variable interest entity" ("VIE") identification requires an economic analysis of the rights and obligations of an entity's assets, liabilities, equity, and contracts or arrangements with other parties. Variable interests are interests in an entity that change with the fair value of the net assets[2] exclusive of the variable interest.

Under FIN 46, entities meeting certain specific criteria are deemed "variable interest entities" ("VIE"). If an entity is determined to be a VIE, a determination must be made as to whether there is a "primary beneficiary". The "primary beneficiary" is the enterprise that will absorb a majority of the entity's expected losses, receive a majority of the entity's expected residual returns, or both. The primary beneficiary must consolidate the VIE. FIN 46 required extensive judgment and estimates, but provided very little assistance in making them. Companies struggled with how to implement FIN 46. FIN 46 was effective immediately for entities created on or after February 1, 2003, however, its implementation was later deferred.

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[1] Since 1973, FASB has been the designated organization in the private sector for establishing standards of financial accounting and reporting. Those standards govern the preparation of financial reports. They are officially recognized as authoritative by the Securities and Exchange Commission (Financial Reporting Release No. 1, Section 101) and the American Institute of Certified Public Accountants (Rule 203, Rules of Professional Conduct, as amended May 1973 and May 1979).

[2] FIN 46R uses the terms "expected losses" and "expected residual returns" to describe the expected variability in the fair value of the entity's net assets exclusive of variable interests. Expected losses and expected residual returns refer to amounts discounted and otherwise adjusted for market factors and assumptions. Expected variability is the sum of the absolute values of the expected residual returns and the expected loss.

In December 2003, FASB issued a revised FIN 46 ("FIN 46R"). FIN 46R was effective for financial statements for periods ending after March 15, 2004. The summary section of FIN 46R is attached. Although FIN 46R provided some clarification, there are many issues in FIN 46R that are subject to interpretation. In early 2004, the utilities became aware that certain interpretations of FIN 46R resulted in independent power producers ("IPPs") being deemed VIEs. Further, an interpretation that a purchaser absorbing fuel oil price risk (regardless of any current ability to recover the changes in price from customers) was the "primary beneficiary" of the VIE and required the purchaser to consolidate the VIE.

In early 2004, there was considerable uncertainty as to the application of FIN 46R. The utilities participated in industry discussions on the applicability of FIN 46R to PPAs. In March 2004, the Edison Electric Institute ("EEI") wrote to the FASB providing EEI's assessment of the applicability of FIN 46R in specific PPA scenarios and requesting a delay in the implementation of FIN 46R.[3] FASB did not respond to EEI's request for a delay in implementation. In March 2004, the utilities determined that all the purchase power agreements were potential VIEs and that it might be possible that the utilities may be deemed the primary beneficiary. In compliance with FIN 46R, the utilities requested information from the independent purchase power producer which it had a purchase power agreement ("PPA") with in order to determine the proper accounting treatment of the specific PPA.

Although FASB did not directly respond to the EEI letter raising issues with respect to the applicability of FIN 46R to purchase power agreements, the Emerging Issues Task Force ("EITF" or "Task Force")[4], addressed certain issues with respect to the implementation of FIN 46 in EITF Issue No. 04-7 "Determining Whether an Interest Is a Variable Interest in a Variable Interest Entity" ("ETIF 04-7"). EITF 04-7 raised two issues: 1) what aspects or components of the variability of an entity's net assets (exclusive of variable interests should be considered when determining whether an interest is a variable interest and 2) when determining whether an interest is a variable interest, whether long positions of a VIE that are synthetically created by derivative transactions should be considered in the same manner as long positions created by cash

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[3] See attached letter dated March 16, 2004 from EEI to FASB.

[4] The mission of the EITF is to assist the FASB in improving financial reporting through the timely identification, discussion, and resolution of financial accounting issues within the framework of existing authoritative literature. The EITF was designed to promulgate implementation guidance within the framework of existing authoritative literature to reduce diversity in practice on a timely basis. Task Force members are drawn from a cross section of the FASB's constituencies, including auditors, preparers, and users of financial statements. If the EITF can reach a consensus on an issue, usually that is taken by the FASB as an indication that no Board action is needed. The Task Force meets periodically throughout the year. If the Task Force is unable to reach a consensus, it may be an indication that action by the FASB is necessary. A consensus on an EITF issue is reached if no more than three of the voting members present at the meeting object to a proposed position on an issue. Although FASB Board members do not vote on consensuses at Task Force meetings, all consensuses are subject to ratification by the FASB at an ensuing open public meeting of the Board.

transactions. In June 2004, EITF discussed issue 1 and asked the FASB staff and a working group to further develop material to be discussed at a future meeting. The EITF did not discuss issue 2. Further discussion is expected at a future meeting.

Need for requiring information to comply with FIN 46R

Based on consultation with our independent certified public accountants ("CPA"), KPMG LLP, and outside counsel, Goodsill, Andersen, Quinn, and Stifel, HECO determined that any new or amended contracts with IPPs will include provisions to require that the IPP provide information in order for the utility to comply with FIN 46R. The requirement to provide information is necessary since there are no scope exceptions for entities created after December 31, 2003 (i.e. any new contracts).

The inability to comply with FIN 46R may preclude the Company from obtaining an opinion from our independent CPA that the Company's financial statements are prepared in accordance with generally accepted accounting principles. HECO and its parent company, Hawaiian Electric Industries, Inc. ("HEI") have publicly-traded securities registered with the Securities and Exchange Commission ("SEC") and must provide financial statements certified by a CPA in its registration statements filed with the SEC. Further, if it is determined that the IPP is a VIE and that the utility is the primary beneficiary, the utility would have to consolidate the IPP in its financial statements. If consolidation is required, HECO management must also assess the IPP's internal controls over financial reporting in order to comply with section 404 of the Sarbanes-Oxley Act of 2002 ("SOX 404"). The inability to provide certified financial statements may result in SEC[5] action against the Company.

Information necessary to address the applicability of FIN 46R

FIN 46R uses the term "entity" to refer to any legal structure used to conduct activities or to hold assets. FIN 46R applies to all entities except the following: (paragraph 4)

a. Not-for-profit organizations are not subject to this Interpretation unless they are used by business enterprises in an attempt to circumvent the provisions of this Interpretation.
b. Employee benefit plans subject to specific accounting requirements in existing FASB Statements are not subject to this Interpretation.
c. Registered investment companies are not required to consolidate a variable interest entity unless the variable interest entity is a registered investment company.

[5] The SEC has statutory authority to establish financial accounting and reporting standards for publicly held companies under the Securities Exchange Act of 1934. Throughout its history, however, the Commission's policy has been to rely on the private sector for this function to the extent that the private sector demonstrates ability to fulfill the responsibility in the public interest.

d. Transferors to qualifying special-purpose entities and "grandfathered" qualifying special-purpose entities subject to the reporting requirements of FASB Statement No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities,* do not consolidate those entities.
e. No other enterprise consolidates a qualifying special-purpose entity or a "grandfathered" qualifying special-purpose entity unless the enterprise has the unilateral ability to cause the entity to liquidate or to change the entity in such a way that it no longer meets the requirements to be a qualifying special-purpose entity or "grandfathered" qualifying special-purpose entity.
f. Separate accounts of life insurance enterprises as described in the AICPA Auditing and Accounting Guide, *Life and Health Insurance Entities,* are not subject to this Interpretation.
g. An enterprise with an interest in a variable interest entity or potential variable interest entity created before December 31, 2003, is not required to apply this Interpretation to that entity if the enterprise, after making an exhaustive effort, is unable to obtain the information necessary to (1) determine whether the entity is a variable interest entity, (2) determine whether the enterprise is the variable interest entity's primary beneficiary, or (3) perform the accounting required to consolidate the variable interest entity for which it is determined to be the primary beneficiary. The scope exception in this provision applies only as long as the reporting enterprise continues to be unable to obtain the necessary information.
h. An entity that is deemed to be a business (as defined in this Interpretation) need not be evaluated to determine if it is a variable interest entity unless one of the following conditions exists:

    - The reporting enterprise, its related parties, or both participated significantly in the design or redesign of the entity, and the entity is neither a joint venture nor a franchisee.
    - The entity is designed so that substantially all of its activities either involve or are conducted on behalf of the reporting enterprise and its related parties.
    - The reporting enterprise and its related parties provide more than half of the total of the equity, subordinated debt, and other forms of subordinated financial support to the entity based on an analysis of the fair values of the interests in the entity.
    - The activities of the entity are primarily related to securitizations, other forms of asset-backed financings, or single-lessee leasing arrangements.

i. An enterprise is not required to consolidate a governmental organization and is not required to consolidate a financing entity established by a governmental organization unless the financing entity (a) is not a governmental organization and (b) is used by the business enterprise in a manner similar to a variable interest entity in an effort to circumvent the provisions of this Interpretation.

The utilities require any information that would result in the IPP qualifying under any of these scope exceptions. For example, the utility needs additional information to determine whether or not the IPP is a "business" as defined by FIN 46R, Appendix C[6] and might qualify for the business scope exception under paragraph 4(h). The utility did not participate in the design of the IPP therefore paragraph 4(h)(1) does not apply. However, if it is a business, the utility needs information to determine whether substantially all the IPP's activities are conducted on the utility's behalf [paragraph 4(h)(2)]. The utilities do not provide equity, subordinated debt or other forms of subordinated financial support to IPPs, therefore paragraph 4(h)(3) does not apply. Further, the utilities need an indication from the IPPs whether or not its activities are primarily securitizations, other forms of asset-backed financings, or single-lessee leasing arrangements in order to address paragraph 4(h)(4).

In addition to the explicit scope exceptions stated, there is a section of FIN 46R that might be interpreted to be a scope exception for operating leases.[7] See discussion of lease accounting treatment of the contract attached. Information on the expected useful life and fair value of the equipment at inception of the contract is necessary to assess the appropriate lease accounting treatment.

<u>Information necessary to determine whether or not the IPP is a VIE</u>

FIN 46R addresses consolidation by business enterprises of variable interest entities, which have one or more of the following characteristics: (paragraph 5)

a. The equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support provided by any parties, including the equity holders.
b. The equity investors lack one or more of the following essential characteristics of a controlling financial interest:

6 FIN 46R, Appendix C, paragraph C3 states: "The definition of a business for use in this Interpretation is as follows: A business is a self-sustaining integrated set of activities and assets conducted and managed for the purpose of providing a return to investors. A business consists of (a) inputs, (b) processes applied to those inputs, and (c) resulting outputs that are used to generate revenues. For a set of activities and assets to be a business, it must contain all of the inputs and processes necessary for it to conduct normal operations, which include the ability to sustain a revenue stream by providing its outputs to customers." Paragraph C6 states: "If all but a *de minimis* (say, 3 percent) amount of the fair value of the set of activities and assets is represented by a single tangible or identifiable intangible asset, the concentration of value in the single asset is an indicator that an asset rather than a business is being evaluated."

7 FIN 46R, Appendix B, paragraph B24 states: "Receivables under an operating lease are assets of the lessor entity and provide returns to the lessor entity with respect to the leased property during that portion of the asset's life that is covered by the lease. Most operating leases do not absorb variability in the fair value of an entity's net assets because they are a component of that variability. Guarantees of the residual values of leased assets (or similar arrangements related to leased assets) and options to acquire leased assets at the end of the lease terms at specified prices may be variable interests in the lessor entity if they meet the conditions described in paragraph 12 of this Interpretation. Alternatively, such arrangements may be variable interests in portions of a variable interest entity as described in paragraph 13 of this Interpretation."

- The direct or indirect ability to make decisions about the entity's activities through voting rights or similar rights
- The obligation to absorb the expected losses of the entity
- The right to receive the expected residual returns of the entity.

c. The equity investors as a group also are considered to lack characteristic (b)(l) if (i) the voting rights of some investors are not proportional to their obligations to absorb the expected losses of the entity, their rights to receive the expected residual returns of the entity, or both and (ii) substantially all of the entity's activities (for example, providing financing or buying assets) either involve or are conducted on behalf of an investor that has disproportionately few voting rights. For purposes of applying this requirement, enterprises shall consider each party's obligations to absorb expected losses and rights to receive expected residual returns related to all of that party's interests in the entity and not only to its equity investment at risk.

Without additional information on the IPP's financial structure, its investors, and others who may participate in its financial structure, the utility would not be able to apply the requirements of FIN 46R, paragraph 5. The utility requires any information that would indicate that the IPP's activity is conducted on behalf of investors other than the utility that have disproportionately few voting rights. Additional information necessary to assess these criteria may include, amongst other information: amount of equity at risk by any party, ownership documents relating to voting or similar rights (e.g. Articles of Incorporation, partnership agreement), any documents addressing participation in losses or earnings of the entity (e.g. ownership agreements, debt and other borrowing documents).

<u>Information needed to determine whether or not the utility is the "primary beneficiary"</u>

FIN 46R provides the following guidance to address which entity should consolidate the VIE (paragraph 12):

> "An enterprise shall consolidate a variable interest entity if that enterprise has a variable interest (or combination of variable interests) that will absorb a majority of the entity's expected losses, receive a majority of the entity's expected residual returns, or both. An enterprise shall consider the rights and obligations conveyed by its variable interests and the relationship of its variable interests with variable interests held by other parties to determine whether its variable interests will absorb a majority of a variable interest entity's expected losses, receive a majority of the entity's expected residual returns, or both. If one enterprise will absorb a majority of a variable interest entity's expected losses and another enterprise will receive a majority of that entity's expected residual returns, the enterprise absorbing a majority of the losses shall consolidate the variable interest entity."

In order to assess this provision, the utility needs information of which entities have potential economic interest in the IPP, any "related party" relationships between the entities as defined under FIN 46R[8], and an understanding of how the interests are impacted by economic variability.

Potential losses that will be absorbed by other potential interests in an IPP may include but are not limited to: capital expenditures, debt service (if any), operation of the plant, and environmental compliance. Potential losses that will be absorbed by the utility may

[8] FIN 46R, paragraphs 16 and 17 state: "16. For purposes of determining whether it is the primary beneficiary of a variable interest entity, an enterprise with a variable interest shall treat variable interests in that same entity held by its related parties as its own interests. For purposes of this Interpretation, the term *related parties* includes those parties identified in FASB Statement No. 57, *Related Party Disclosures,* and certain other parties that are acting as de facto agents or de facto principals of the variable interest holder. The following are considered to be de facto agents of an enterprise:

a. A party that cannot finance its operations without subordinated financial support from the enterprise, for example, another variable interest entity of which the enterprise is the primary beneficiary
b. A party that received its interests as a contribution or a loan from the enterprise
c. An officer, employee, or member of the governing board of the enterprise
d. A party that has (1) an agreement that it cannot sell, transfer, or encumber its interests in the entity without the prior approval of the enterprise or (2) a close business relationship like the relationship between a professional service provider and one of its significant clients. The right of prior approval creates a de facto agency relationship only if that right could constrain the other party's ability to manage the economic risks or realize the economic rewards from its interests in a variable interest entity through the sale, transfer, or encumbrance of those interests.

17. If two or more related parties (including the de facto agents described in paragraph 16) hold variable interests in the same variable interest entity, and the aggregate variable interest held by those parties would, if held by a single party, identify that party as the primary beneficiary, then the party, within the related party group, that is most closely associated with the variable interest entity is the primary beneficiary. The determination of which party within the related party group is most closely associated with the variable interest entity requires judgment and shall be based on an analysis of all relevant facts and circumstances, including:

a. The existence of a principal-agency relationship between parties within the related party group
b. The relationship and significance of the activities of the variable interest entity to the various parties within the related party group
c. A party's exposure to the expected losses of the variable interest entity
d. The design of the variable interest entity."

The glossary of FAS 57 defines related parties as follows: "Affiliates of the enterprise; entities for which investments are accounted for by the equity method by the enterprise; trusts for the benefit of employees, such as pension and profit-sharing trusts that are managed by or under the trusteeship of management; principal owners of the enterprise; its management; members of the immediate families of principal owners of the enterprise and its management; and other parties with which the enterprise may deal if one party controls or can significantly influence the management or operating policies of the other to an extent that one of the transacting parties might be prevented from fully pursuing its own separate interests. Another party also is a related party if it can significantly influence the management or operating policies of the transacting parties or if it has an ownership interest in one of the transacting parties and can significantly influence the other to an extent that one or more of the transacting parties might be prevented from fully pursuing its own separate interests."

include but are not limited to: electric price fluctuations and the commitment to take output of the facility under certain conditions. The information requirements to address this section of FIN 46R are very broad since the utility may not be aware of agreements or potential situations that could potentially create variability in an IPP's interests.

Reassessment under FIN 46R

FIN 46R specifies situations under which the determination of whether an IPP is a variable interest entity would need to be reassessed. Paragraph 7 of FIN 46R states that the initial determination of whether an entity is a variable interest entity shall be reconsidered if one or more of the following occur:

a. The entity's governing documents or contractual arrangements are changed in a manner that changes the characteristics or adequacy of the entity's equity investment at risk.
b. The equity investment or some part thereof is returned to the equity investors, and other interests become exposed to expected losses of the entity.
c. The entity undertakes additional activities or acquires additional assets, beyond those that were anticipated at the later of the inception of the entity or the latest reconsideration event, that increase the entity's expected losses.
d. The entity receives an additional equity investment that is at risk, or the entity curtails or modifies its activities in a way that decreases its expected losses.

FIN 46R specifies situations under which the determination of whether the utility is the primary beneficiary would need to be reassessed. Under FIN 46R paragraph 15, an enterprise with an interest in a variable interest entity shall reconsider whether it is the primary beneficiary of the entity if the entity's governing documents or contractual arrangements are changed in a manner that reallocates between the existing primary beneficiary and other unrelated parties (a) the obligation to absorb the expected losses of the variable interest entity or (b) the right to receive the expected residual returns of the variable interest entity. Also under FIN 46R paragraph 15, the primary beneficiary also shall reconsider its initial decision to consolidate a variable interest entity if the primary beneficiary sells or otherwise disposes of all or part of its variable interests to unrelated parties or if the variable interest entity issues new variable interests to parties other than the primary beneficiary or the primary beneficiary's related parties. A holder of a variable interest that is not the primary beneficiary also shall reconsider whether it is the primary beneficiary of a variable interest entity if that enterprise acquires additional variable interests in the variable interest entity.

These reassessment requirements create an ongoing need for information in order to comply with FIN 46R.

Compiance with SOX 404

If consolidation under FIN 46R is required, HECO management must assess the IPP's internal controls over financial reporting in order to comply with section 404 of the Sarbanes-Oxley Act of 2002. The Company's independent certified public accountant ("CPA") must also certify management's internal control assessment process as well as perform its own testing of internal controls. HECO has publicly-traded securities registered with the SEC and must provide financial statements certified by a CPA in its registration statements filed with the SEC. The inability to provide certified financial statements (including attestation to internal controls) may result in SEC action against the Company.

Lease Accounting

For financial statement reporting purposes, a lease is defined as an agreement conveying the right to use property, plant, or equipment (land and/or depreciable assets) usually for a stated period of time. Lease accounting addresses the issue of how a lease is accounted for financial reporting purposes. There are at least two parties to a lease arrangement: lessor and lessee. Generally, operating leases are accounted for as expenses by the lessee while the lessor would report the investment in assets, related depreciation expense and lease revenue. On the other hand, if the agreement is deemed a capital lease, a lessee would report an investment in asset, related depreciation, a capital lease obligation and related interest expense.

In order to determine the applicability of lease accounting to a PPA, it must first be determined whether the PPA is a lease. In May 2003, EITF issued EITF Issue No. 01-8 "Determining Whether an Arrangement Contains a Lease." EITF 01-8 defines a lease as an agreement that conveys the right to use property, plant, or equipment (land and/or depreciable assets) usually for a stated period of time.

If it is determined that a PPA is a lease, it must be determined to be either a capital lease or an operating lease. The primary source of accounting guidance as to whether a lease is a capital lease or an operating lease is Statement of Financial Accounting Standards No. 13 "Accounting for Leases" (FAS 13).

Determining whether or not the PPA is a lease

EITF 01-8 states that an arrangement conveys the right to use property, plant, or equipment ("PPE") if any one of the following conditions is met: (paragraph 12)

a. The purchaser has the ability or right to operate the PPE while obtaining or controlling more than a minor amount of the output or other utility of the PPE,
b. The purchaser has the ability or right to control physical access to the underlying PPE while obtaining or controlling more than a minor amount of the output or other utility of the PPE, or
c. Facts and circumstances indicate that it is remote that one or more parties other than the purchaser will take more than a minor amount of the output or other utility that will be produced or generated by the PPE during the term of the arrangement, and the price that the purchaser (lessee) will pay for the output is neither contractually fixed per unit of output nor equal to the current market price per unit of output as of the time of delivery of the output.

Determining whether a lease is a capital lease or operating lease

If the PPA is deemed a lease, the utility needs to determine whether the lease is a capital lease or an operating lease. If at its inception, a lease meets one or more of the following four criteria, the lease shall be classified as a capital lease by the lessee: (FAS 13 paragraph 7)

a. The lease transfers ownership of the property to the lessee by the end of the lease term.
b. The lease contains a bargain purchase option.
c. The lease term[1] is equal to 75 percent or more of the estimated economic life of the leased property.
d. The present value at the beginning of the lease term of the minimum lease payments, equals or exceeds 90 percent of the excess of the fair value of the leased property.

   If the beginning of the lease term falls within the last 25 percent of the total estimated economic life of the leased property, including earlier years of use, the criteria (c) and (d) shall not be used to classify the lease.

PPAs generally would not transfer ownership of the property therefore test (a) is usually not met. The PPA would also generally not contain a bargain purchase option, therefore test (b) is usually not met.

The utility requires an engineering estimate of the economic useful life of the equipment in order to address paragraph 7(c).

In order to address paragraph 7(d), the utilities must assess whether the payments under the contract meet the definition of a minimum lease payment. Minimum lease payments exclude payments meeting the "contingent rental" criteria. Contingent rentals as defined by SFAS No. 29 "Determining Contingent Rentals an amendment of FASB 13" are excluded from minimum lease payments. FAS 29 defines contingent rentals as follows: (paragraph 11 of FAS 29, amending paragraph 5(n) of FAS 13)

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[1] As defined under paragraph 5f: "The fixed noncancelable term of the lease plus (i) all periods, if any, covered by bargain renewal options (as defined in paragraph 5(e)), (ii) all periods, if any, for which failure to renew the lease imposes a penalty on the lessee in an amount such that renewal appears, at the inception of the lease, to be reasonably assured, (iii) all periods, if any, covered by ordinary renewal options during which a guarantee by the lessee of the lessor's debt related to the leased property is expected to be in effect, (iv) all periods, if any, covered by ordinary renewal options preceding the date as of which a bargain purchase option (as defined in paragraph 5(d)) is exercisable, and (v) all periods, if any, representing renewals or extensions of the lease at the lessor's option; however, in no case shall the lease term extend beyond the date a bargain purchase option becomes exercisable. A lease which is cancelable (i) only upon the occurrence of some remote contingency, (ii) only with the permission of the lessor, (iii) only if the lessee enters into a new lease with the same lessor, or (iv) only upon payment by the lessee of a penalty in an amount such that continuation of the lease appears, at inception, reasonably assured shall be considered "noncancelable" for purposes of this definition."

> "The increases or decreases in lease payments that result from changes occurring subsequent to the inception of the lease in the factors (other than the passage of time) on which lease payments are based, except as provided in the following sentence. Any escalation of minimum lease payments relating to increases in construction or acquisition cost of the leased property or for increases in some measure of cost or value during the construction or pre-construction period, as discussed in *FASB Statement No. 23,* "Inception of the Lease," shall be excluded from contingent rentals. Lease payments that depend on a factor directly related to the future use of the leased property, such as machine hours of use or sales volume during the lease term, are contingent rentals and, accordingly, are excluded from minimum lease payments in their entirety. However, lease payments that depend on an existing index or rate, such as the consumer price index or the prime interest rate, shall be included in minimum lease payments based on the index or rate existing at the inception of the lease; any increases or decreases in lease payments that result from subsequent changes in the index or rate are contingent rentals and thus affect the determination of income as accruable."

An evaluation of the level of uncertainty associated with the lease payments is necessary to determine whether the lease payments depend on a factor that does not exist or is not measurable at the inception of the lease. In general, "as available" payments would meet the criteria of contingent rental payments and as such are not included in minimum lease payments for purposes of test 7(d) under FAS 13. Generally, capacity payments are included in minimum lease payments and under certain conditions, energy payments for certain contracts may also be included in minimum lease payments.

A PPA meeting either test 7(c) or (d) would be deemed a capital lease. The accounting for a capital lease would require that the present value of the minimum lease payments be reflected as a lease asset and a lease obligation on HECO's books. If there are no minimum lease payments, there would be no lease asset and lease obligation to record. In addition, however, by definition, a capital lease is not an operating lease, and therefore would not qualify for a scope exception as an operating lease under FIN 46R. If there are minimum lease payments, the present value of which is greater than 90% of the fair value of the property, it would result in a capital lease obligation being recorded.

DBEDT-IR-3-HECO/CA

Ref.: Joint Proposal, Pages 6-7.

(a) Please explain what the "capital lease obligations" relating to purchase power agreements mean, and please describe the financial impact on the utility.

(b) In what Commission dockets is this issue being addressed?

Response:

(a) Capital lease obligations are described in response to DBEDT-IR-2-HECO/CA.

Investors are very sensitive to financial strength considerations when they decide where to invest their money. If HECO's financial strength is not maintained, more risk adverse investors will invest their money elsewhere. This, in turn, will have negative implications for HECO's customers because it will reduce the demand for the Company's securities and will increase its cost of capital. Further, under adverse market conditions, it may be difficult to attract capital. Purchased power agreements which meet certain criteria (described in response to DBEDT-IR-2-HECO/CA) result in capital lease obligations. Capital lease obligations are a form of debt. Companies that have more debt (less equity) are deemed to have higher financial risk than companies that have less debt (more equity). In order to maintain financial integrity, the Company establishes and maintains certain target equity ratios. Rebalancing cost is the cost of foregoing the issuance of the debt and instead financing with equity (and some proportion of hybrids or preferred) in order to maintain the capital structure (i.e. equity ratio) which would have existed absent the purchased power obligation. Because the cost of equity is higher than the cost of debt, infusion of additional equity and reduction in the amount of debt results in an overall higher cost of capital. Because of the impact PPAs have on the cost of capital, HECO also analyzes the cost of rebalancing in evaluating the cost of PPAs.

(b) Dockets in which the capital lease issue has been addressed include the following:

- Competitive Bidding (Docket No. 03-0372)
- HECO 2005 Test Year Rate Case (Docket No. 04-0113, HECO T-21, pp. 17-22)
- HELCO 2006 Test Year Rate Case (Docket No. 05-0315, HELCO T-18, pp. 19-24)
- HECO 2007 Test Year Rate Case (Docket No. 2006-0386, HECO T-19, pp. 33-41)
- HECO 2009 Test Year Rate Case (Docket No. 2008-0083, HECO T-20, pp. 33-52)

The Companies do not currently have any purchased power agreement which results in a capital lease obligation being recorded on the balance sheet. If the Company were to enter into a purchased power agreement which it determined would result in a capital lease obligation, the issue would be addressed in the application for approval of the PPA.

DBEDT-IR-4-HECO/CA

Ref.: Joint Proposal (KEMA), Page 9.

Is it HECO's and CA's position that FiTs cannot effectively encourage and develop large dispatchable resources? Please explain.

Response:

The FIT complements other mechanisms to acquire renewable energy, out of recognition that these mechanisms may be more appropriate in targeting development of certain resources. For example, larger dispatchable resources or technologies requiring large economies of scale are more effectively encouraged and developed using the Commission's Framework for Competitive Bidding. Therefore the proposed FIT targets smaller scale resources.

The FIT mechanism is also intended to support predictability and streamlining in pricing, contracting, and project development, to the benefit of both renewable energy producers and ratepayers. Therefore the FIT targets those projects for which Hawaii-specific costs and technical requirements are better understood. Other resources for which a FIT is not immediately available can be contracted on a one-off basis with the utility under existing processes.

DBEDT-IR-5-HECO/CA

Ref.: HECO Response to DBEDT-IR-8.

Please identify the "policies and processes" that may be implemented in this docket that HECO considers will be "final" and will not change without Commission approval.

Response:

The FIT update process will review, evaluate and modify as appropriate the pricing, eligible technologies, project sizes and annual targets determined in development of the initial FIT. The methodologies that will be adopted and implemented in this docket are not anticipated to change during the FIT update. This would include but not necessarily be limited to the contracting process that defines the steps for processing requests for service under Schedule FIT and executing a Schedule FIT agreement. The contracting process and other administrative procedures are described in Appendix II – Schedule FIT Contracting Overview of the Companies and the CA's jointly proposed Tariff Sheets.

Hawaii Renewable Energy Alliance

HREA-HECO/CA-OSOP-IR-1

Regarding the statement on page 4 that FiTs should involve an offer of a "fixed price contract," would the HECO and the CA consider a "levelized price contract" with an appropriate escalation metric as an alternative? Why should the developer have to assume the risk of a fixed price contract? Specifically, HREA is concerned that a fixed price contract will cause uncertainty to the developer in terms of the risk associated with predicting future inflation, and thus arriving at an appropriate fixed price for a 20 year term.

Response:

FIT payment rates should be stabilized to provide predictability to both the developer and the utility. In setting the FIT rates, reasonable assumptions on cost factors, including inflation, should be used that fairly allocate risk to both the developer and the utility. "Stabilized" payment rates can either be fixed over the term of the agreement, or set at a lower initial level and escalated on a periodic basis by a pre-established percentage amount.

HREA-HECO/CA-OSOP-IR-2

Regarding the discussion of design considerations on page 5, HREA would agree there are risks associated with permitting projects and that those risks do generally increase with the type and size of the project, the classification and ownership of the land on which the project would be situated, interconnection requirements, project financing and a host of related factors. Why not let the developers assume these risks, rather than arbitrarily determining the acceptable level of risk from the HECO/CA perspective, such as we perceive has been done in the HECO/CA FiT proposal? Specifically, if the goal is to facilitate a "sea change" in our use of renewable energy, why are you effectively 'tying some boats to the dock," such that they cannot be sailed or rowed to our renewable future?

Response:

The HECO Companies propose that the initial FIT be focused on projects that are reasonably predictable in their development timeframes, capital and operations and maintenance costs, and performance. As stated in the HCEI Agreement, "feed-in tariffs are beneficial for the development of renewable energy, as they provide predictability and certainty with respect to the future prices to be paid for renewable energy and how much of such energy the utility will acquire." (HCEI Agreement, page 16) Predictability and certainty should be provided to the utility and their ratepayers as well as project developers.

Alexander & Baldwin, Inc. through its division, Hawaiian Commercial & Sugar Company

HC&S-IR-7

Does the HECO Companies plan to include FiT generation in its QF-in/QF-out calculation of avoided cost utilizing P-Month, a PC-based production stimulation model?

a. If yes, will all FiT generation be included in the QF-in run? If not, please explain in detail why not?
b. If yes, will only as-available FiT generation be included in the QF-out run? Or will both as-available and firm FiT generation be included in the QF-out run. In either case, please explain your reasoning?
c. If yes, is it expected that additional regulating reserve will be required for each HECO Companies' grid system? If yes, will this lower the rate paid to existing IPPs who are paid the utilities' avoided cost?

Response:

No. HECO, HELCO and MECO will not include as-available generation acquired under feed-in tariffs in its calculation of avoided energy costs using the QF-in/QF-out methodology that is described in the Updated Stipulation to Resolve Proceeding, dated December 29, 2006, in Docket No. 7310. This is because the as-available generators will be paid at feed-in tariff rates and not at the avoided energy cost rates determined using the QF-in/QF-out methodology.

a. Not applicable.

b. Not applicable.

c. Not applicable.

The Solar Alliance

SA-IR-7

Does the HECO Companies plan to revise its Rule 14 to make it consistent with the intent of the HCEI and more user friendly for potential FiT generators?

a. Specifically, does the HECO Companies plan to revise or eliminate Rule 14, Appendix I, Section 2. General Interconnection Guidelines d. Utility Feeder Penetration. This section has a ten percent feeder penetration which is inconsistent with the Hawaii Clean Energy Agreement and the "Location Value Maps" referenced in this section needs to be reevaluated.

b. Please explain why it takes at least 6+, (exact time frame is not known since the current application is still ongoing), months to do an Interconnection Requirement Study at the 10% feeder distribution level. How will the HECO Companies address minimizing the extended IRS resolution timeframe at the low level of DG penetration and still achieve the objectives of the HCEI?. (HECO Companies have shown an inability to timely respond/process to the current IRS triggers in Rule 14.)

c. With the lower level of 10% feeder distribution requiring a IRS evaluation, what are the plans, process, and timeline that the HECO Companies are willing to commit to in regards to the 15% ,(HCEI proposed), 12 kVa circuit penetration evaluation?

d. Specifically, does the HECO Companies plan to revise or eliminate Rule 14, Section 3 Design Requirements, f. Supervisory control? (This requirement creates a "system size benchmark" which third party investors may not want to exceed, fearing additional costs, studies, remote curtailment.)

Response:

a. The HECO companies plan to revise Rule 14H, Appendix I, Section 2.d. (Utility Feeder Penetration) to increase the feeder penetration threshold to determine when additional technical study may be required from 10% to 15%, to be consistent with the Hawaii Clean Energy Agreement.

b. The HECO companies acknowledge that some, but not all, Interconnection Requirement Studies (IRS) have taken longer than six months. However, it is essential that proper technical evaluations are conducted to ensure the interconnection of the distributed generators will be done safely and will not adversely affect the utility grid system. In some cases, extensive time is spent between developers and the utility company to develop and clarify the technical information needed to perform the IRS. Furthermore, if there are several DG connections in the same area, the study needs to analyze how each affects each other. Issues such as overload conditions, protection, islanding, communication, performance standards (if intermittent generation) are also covered in this complex study. Additionally, the IRS is normally performed by a consultant. It is becoming increasingly difficult to find qualified consultants to conduct the study due to the limited number of qualified consultants available to respond to an ever increasing number of study requests. One of the options the HECO companies are looking at is increasing staff and performing additional technical training such that more of the studies can be done in-house. Lastly, as outlined in Rule 14H, the customer may utilize its employees or a qualified third-party consultant to perform the technical study provided that there is a mutual agreement between the HECO company and the customer (to be documented in writing).

c The HECO Companies' plans, process, and timeline with regard to the 15% feeder penetration issue are outlined in Appendix III (Interconnection Process Overview) of the existing Rule 14H.

d The HECO Companies do not currently have any plans to revise or eliminate the design requirement for supervisory control as stated in Rule 14H, Appendix I, Section 3.f. (Supervisory Control).

Tawhiri Power LLC

TPL-IR-10

HECO has acknowledged distribution-level generation that is not curtailable may increase the curtailment of transmission-level renewables. In that event:

a. Does HECO/CA intend to propose a solution to avoid and/or remedy such situations? If so, what is the proposal and when would such proposal be made?
b. Would HECO/CA support postponing FiT implementation in systems with high penetration levels of renewables until this issue is resolved?
c. Would HECO/CA support convening a meeting to resolve this issue?

<u>Response:</u>

a. The responses to TPL-IR-1 and TPL-IR-2, filed February 11, 2009, describe the conditions under which transmission-side resources are curtailed and the possible mechanisms for existing and future curtailments. In consideration of the overall objectives as laid out in the HCEI agreement, future curtailments of transmission-side resources may be necessary to accommodate future renewable energy additions resulting from FIT or other mechanisms, and may also be necessary if there are future reductions in demand. FIT is proposed as one means of increasing and diversifying the total amount of renewable energy on the systems by targeting certain types of projects. As discussed in TPL-IR-2, the impact of FIT generation on the amount of load served by transmission side resources would be dependent upon the specific characteristics of the generation targeted by the FIT. This aggregate effect on transmission-side renewable energy producers could be one consideration in the establishment of the system targets for FIT generation in various categories and of the types of generation which FIT encourages.

b. The HECO companies are not amenable to postponing the implementation of FIT on the systems with high renewable energy penetrations. Rather, the design of the FIT will take into consideration the unique generation mix on each system in establishing the system targets for FIT generation and their technical characteristics. The proposed FIT would establish annual FIT contracted capacity targets.

c. The HECO companies do not support a meeting for this purpose, as the proceedings of this docket and the structure of the proposed FIT, provide a better means for the Company to communicate its position, and for Tawhiri to provide feedback, with visibility to all interested parties.

TPL-IR-11

Please provide documentation of the following examples you cited in your response to Haiku Design & Analysis' Information Request No. 5 To HECO ("HDA/HECO-IR-5") as evidence of the measures already taken by HELCO to improve it "ability to effectively integrate existing and new variable generators" with respect to:

a. "modifications to the HELCO AGC system to reduce the responsiveness of the system to short term fluctuations in power output of as-available generation to avoid overcompensating for these types of fluctuations;"
b. "modifications and tuning of the control systems for HELCO generating units to increase their responsiveness to respond to fluctuations in as-available generation output;"
c. "increasing the regulating reserve carried on the HELCO grid to provide greater upward ramping capability of online generators to respond to sustained drop offs of as-available generation;"
d. "HELCO transmission projects which have increased east-to-west transmission capacity that also allow for greater operating flexibility of dispatchable generation to reduce excess energy and curtailment of as-available generation;"
e. "a HELCO system stability study to define the minimum amount of steam generation (i.e., generation with higher rotational inertia) that is required to run at all times to ensure the stability of the system during typical emergency events such as transmission system faults, thus allowing better understanding and quantification of the amount of wind and PV energy (i.e., generation with very little to no rotational inertia) that the system can reliably accommodate;"
f. the system studies being undertaken "to better understand what additional modifications are needed in operating practices and existing generation and T&D equipment, as well as the types and attributes needed from new demand response programs and generating units in order to increase the grid's ability to integrate as available generation"; and
g. The study being initiated "to research and develop wind forecasting capabilities that predicts periods of higher risk for large and rapid wind ramping events using available meteorological data available for the Hawaii Island system."

Response:

a) Modifications to the AGC system are described in the following two EPRI reports:

EPRI Evaluation of the Effectiveness of AGC Alterations for Improved Control with Significant Wind Generation. EPRI, Palo Alto, CA: 2007. 1018715.

Evaluation of the Impacts of Wind Generation on HELCO AGC and System Performance – Phase 2. EPRI, Palo Alto, CA: 2009. 1018716.

The modifications involved changes in programming and changes in AGC and unit tuning parameters.

b) Some of the modifications made to generating unit controls are mentioned in the EPRI reports referenced above, such as a change in the droop setting for a combined cycle facility (removing deadband). Other recent changes include new turbine governor control for a steam unit to enable more responsiveness to AGC over greater dispatchable range, and combustion controls work at HELCO steam plants to improve control during load ramps.

c) There has been both a change in reserve allocation and in the total average reserve up. The change in reserve allocation was accomplished by creating a difference between the economic dispatch limit and the regulating limit under AGC control which forces reserve to be allocated among several units rather than allowing economic allocation of reserve. The increase in average reserves is in part due to the practice of carrying additional reserves during periods of observed volatility (ramping) of the wind plants. These operational impacts are discussed in the second EPRI report. Additional upward reserve also results from the acceptance of as-available energy onto the system during periods when only must-run generation is online, which forces generation to lower operating points.

d) Reconductoring of the Waimea-Keamuku and Waimea-Ouli lines (also referenced as the 7200 and 7300 lines) has been completed. Prior to reconductoring, these lines were subject to overloads under certain configurations and dispatches which at times, required curtailment of wind plant output from Hawi Renewable Development (HRD) wind plant.

e) HELCO contracted an engineering firm (Electric Power Systems Inc) to perform a series of system impact planning studies to evaluate various aspects of the impact of renewable generation such as wind and distributed generation on system stability and frequency control. Item (e) references a study conducted in 2006, which attempted to define the boundary for stable operation on the HELCO system with various generation mixes, and develop new load-shedding schedule and operating recommendations. One of the findings of the evaluation was that the HELCO steam units are critical for maintaining system stability during transient faults and following unit trips, due to the inertial response and also due to the time frame of the governor response. It was found that displacement of steam units decreased system stability and that system collapse was possible unless a minimum number of steam units are kept online.

f) Item (f) in the response discusses in general, the fact that there are continuing studies being done by all three of the Hawaiian Electric Companies, regarding renewable energy integration issues. Some studies are in the proposal stage, but others have been completed such as the series of studies that were performed by Electric Power Systems, Inc (EPS)described in the response above to item (e). As part of a follow-up study to the one described above which determined the critical role of steam plants in HELCO's system stability, system experiments were conducted to collect dynamic response measurements, and to confirm and refine the dynamic stability models for the generating units. This was undertaken due to the fact that the previous study confirmed HELCO is operating close to the limits of system stability, which makes it important to accurately model transient stability and dynamic stability parameters. The data improvements have been incorporated into the planning models used to evaluate system impacts of generation additions on the HELCO system. This study also verified that the Shipman units could serve as one of the stabilizing units in the event other of the HELCO steam units is unavailable. Another study expected to be completed in the first quarter of this year (2009) by EPS evaluates the impact of distributed generation resources connected under minimal IEEE 1547 trip settings on the HELCO system and its underfrequency load-shed scheme. In addition to these types of studies, engineers from the HECO companies participate in various organizations and venues such as the NERC task force on variable generation integration, various IEEE/PES conferences, Utility Wind Interest Group, EPRI, and other industry events to keep informed about renewable integration issues and industry developments.

g) As part of its ongoing work, HELCO operations engineers have contacted various wind forecasting entities to evaluate the potential of wind forecast services to improve reliability or lower operational costs through forecasts of wind power. The greatest system benefit would result from anticipating periods of high volatility, or providing advanced notice of ramps, in the near-term and intra-hour time frame. Utility experience with forecasts have shown that the commercially available forecasting services have not had good success in accurately predicting the timing and magnitude of ramp events. At times, the smoothing of models to result in the lowest averaging error has created a failure to detect events entirely. This is an area of research and development by entities providing wind forecasting services. As a first-phase of a possible research project for targeted event prediction, a wind forecast supplier will be examining meteorological causes of wind events that result in operational challenges to the HELCO system operator. Based on the analysis of the driving factors for these events, an evaluation will be made as to whether there is potential to detect these events in advance, and provide indication to the system operator, through observational targeting.

TPL-IR-12

Please provide documentation of the following example you cited in your response to HDA/HECO -IR-5 as evidence of the measures already taken by HECO to improve it "ability to effectively integrate existing and new variable generators":

> "[t]he Oahu 'big wind' implementation studies that commenced with the signing of the HCEI Energy Agreement [that] are scoped to provide technical and operational solutions to the integration of grandfathered (from Competitive Bidding) as-available renewable IPP proposals, up to 100 MW of renewable IPP projects from HECO's 2008 Request For Proposals, and up to 400 MW of wind energy imported from Molokai and/or Lanai."

Response:

The quoted passage is prefaced with the sentence, "Going forward, all three of the Hawaiian Electric Companies are **undertaking** system studies to better understand what additional modifications are needed in operating practices and existing generation and T&D equipment, as well as the types and attributes needed from new demand response programs and generating units in order to increase the grid's ability to integrate as-available generation." (emphasis added). Thus, contrary to what is inferred in the question, the big wind implementation studies are not "measures already taken". It should be noted that these studies are combined efforts of the Hawaiian Electric Companies, the National Laboratories of the US Department of Energy ("USDOE"), Department of Business Economic Development and Tourism ("DBEDT"), and key industry consultants. Because these studies are still in progress, specific conclusions have not been made. It is expected that these studies should yield initial study results by the end of 2009.

TPL-IR-13

Assuming existing renewable energy contracts may continue to be paid at avoided energy costs after FiT implementation had commenced, please answer the following:

a. Did HECO conduct simulation studies of the impact of different levels of FiT generation penetration on posted avoided costs?

b. If the answer to TPL-IR-13.a is in the affirmative, please provide documentation of the methodology employed to calculate the avoided costs, the results attained and the conclusions reached.

c. If the answer to TPL-IR-13.a is in the negative, when do you intend to conduct such simulation studies?

Response:

a. Assuming that by "posted avoided costs" the question is referencing filed monthly avoided energy cost rates, the Hawaiian Electric Companies have not conducted any hypothetical simulations of the impact of various FIT penetration levels on filed monthly avoided energy rates.

b. Please see response to subpart a.

c. At this time, the Hawaiian Electric Companies do not intend to conduct such simulations studies for various FIT penetration levels. The Hawaiian Electric Companies' filed monthly avoided energy cost rates are calculated in accordance with the methodology described in the Updated Stipulation to Resolve Proceeding, dated December 29, 2006, in Docket No. 7310, and approved by the Commission in Decision and Order No. 24086, dated March 11, 2008. The Qualifying Facility-in ("QF-in)/QF-out methodology described therein uses the amount of energy delivered, on average, by QFs with existing power purchase agreements as the QF block of as-available energy. These QFs are paid at the filed monthly avoided energy cost rates determined by this methodology. Energy producers who will be paid at the FIT rate will not be part of the calculation of avoided costs using the QF-in/QF-out methodology because they will not be paid at the filed monthly avoided energy cost rates.

Zero Emissions Leasing LLC

ZE-IR-101

How much renewable energy generating capacity expressed in megawatts, would you project the islands served by the Hawaiian Electric Companies to have in 5 years if:

(a) no feed-in tariff is adopted by the commission?

(b) the Joint Proposal on Feed-In Tariffs of the HECO Companies and Consumer Advocate (the" Joint Proposal on Feed-in Tariffs") is adopted by the commission?

(c) the Proposal for a Feed-in Tariff of Zero Emissions is adopted by the commission?.

Response:

a. The Companies are committed to achieving the RPS levels identified in Section 9 of the Energy Agreement (pg 18), even if no feed-in tariff is adopted by the Commission. Because RPS is measured on an energy basis (kilowatthours), no specific megawatt power capacity of renewable energy has been projected. The megawatt nameplate capacity of renewable energy is unrelated to RPS levels and to other desirable objectives of the Energy Agreement such as reducing the number of barrels of fossil fuel imported into the State. For example, a renewable energy generator with a nameplate capacity of 100 MW with a 10% capacity factor (due to limitations on the availability of the resource) will generate 87,600,000 kWh in a year. However, a renewable energy generator with a nameplate capacity 1/5th the size or 20 MW but with an 80% capacity factor (due to favorable operational characteristics such as high resource availability, predictable or dispatchable output) will generate 1,401,600,000 kWh in a year or 60% more kilowatthours of energy than the 100 MW renewable energy generator.

b. See our response to subpart a above.

c. See our response to subpart a above.

ZE-IR-102

What would be the total cost to the ratepaying public and the total benefit to the ratepaying public, expressed in dollars, of any additions of renewable energy generating capacity on the islands served by the Hawaiian Electric Companies during the next 5 years if :

(a) no feed-in tariff is adopted by the commission?
(b) the Joint Proposal on Feed-In Tariffs is adopted by the commission?
(c) the Proposal for a Feed-in Tariff of Zero Emissions is adopted by the commission?

Response:

In response to subparts a and b, an important value associated with a feed-in tariff program, as stated in the Energy Agreement, is to, "provide predictability and certainty with respect to the future prices to be paid for renewable energy and how much of such energy the utility will acquire." This is a targeted value to providers of qualifying renewable energy resources. At this time, the Companies have not quantified on a dollar basis the total cost of any additions of renewable energy generating capacity during the next 5-years (which includes feed-in tariff projects and projects acquired through other means) with or without the Joint Proposal Feed-in Tariff.

c. It is difficult to quantify either the costs or benefits in dollars associated with the Zero Emissions proposal. This is due in part to the fact that Zero Emissions' proposal does not appear to consider in any comprehensive manner the critical operational issues which must be addressed as a part of any FIT or other significant renewable energy procurement proposal, particularly with regard to isolated island grid systems.

ZE-IR-103

What would be the cost to the public if Hawaii today experienced a cessation of imported Petroleum for electric power generation and if Hawaii today had:

(a) the amount of renewable energy generating capacity in your response to ZE-IR 101(a)?

(b) the amount of renewable energy generating capacity in your response to ZE-IR-101(b)?

(c) the amount of renewable energy generating capacity in your response to ZE-IR 101(c)?

Response:

If imports of petroleum were to cease as of the date of this response, and if petroleum was unavailable for use in existing generating units, the Hawaiian Electric Companies would not have sufficient generating capacity to serve all of its customers in any of the scenarios delineated in Zero Emission's information request as existing generation resources play, and will continue to play a critical role in the future in providing needed capacity for the State. This includes in particular operational characteristics from existing generators such as dispatchability, load following, frequency and voltage regulation and rotational inertia. Therefore, it is not feasible to determine the cost to the public under these scenarios.

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
PUBLIC UTILITIES COMMISSION	)	DOCKET NO. 2008-0273
	)	
Instituting a Proceeding to Investigate the Implementation of Feed-in Tariffs.	)	
	)	
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HAWAII SOLAR ENERGY ASSOCIATION'S RESPONSES TO INFORMATION REQUESTS FROM HAWAIIAN ELECTRIC COMPANY AND THE DEPARTMENT OF BUSINESS, ECONOMIC DEVELOPMENT AND TOURISM REGARDING ITS OPENING STATEMENT OF POSITION AND PROPOSAL FOR FEED-IN TARIFF DESIGN, POLICIES AND PRICING METHODS

AND

CERTIFICATE OF SERVICE

MARK DUDA
PRESIDENT
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PO Box 37070
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Telephone No.: (808) 735-1467

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate the Implementation of Feed-in Tariffs.	)	DOCKET NO. 2008-0273

HAWAII SOLAR ENERGY ASSOCIATION'S RESPONSES TO INFORMATION REQUESTS FROM HAWAIIAN ELECTRIC COMPANY AND THE DEPARTMENT OF BUSINESS, ECONOMIC DEVELOPMENT AND TOURISM REGARDING ITS OPENING STATEMENT OF POSITION AND PROPOSAL FOR FEED-IN TARIFF DESIGN, POLICIES AND PRICING METHODS

Pursuant to the Commission's Order Approving the HECO Companies' Proposed Procedural Order, as Modified, filed on January 20, 2009, Hawaii Solar Energy Association ("HSEA") hereby submits the following Responses to Information Requests from the HECO Companies and the Department of Business, Economic Development and Tourism on its Opening Statement of Position and Proposal for Feed-in Tariff Design, Policies and Pricing Methods.

Respectfully submitted.

DATED: Honolulu, Hawaii, March 13, 2009

MARK DUDA

President, Hawaii Solar Energy Association

HECO/HSEA-IR-1

Do you agree that in addition to achieving a greater level of renewable energy for the State, reliability, power quality and ratepayer impacts are important considerations that must be addressed as a part of any feed-in tariff (FIT) design? If not, please discuss why not.

RESPONSE:

Yes. However, it is important to keep in mind that: (i) a feed-in tariff is a *price* specification designed to economically motivate the rapid development of renewable energy generation and (ii) that a number of factors outside the scope of this proceeding influence reliability, power quality, and ratepayers impacts.

HECO/HSEA-IR-2
Do you agree that the HECO, MECO and HELCO systems have different technical and reliability considerations? If not, please discuss why not.

RESPONSE:

Yes.

HECO/HSEA -IR-3

Do you agree that due to the existing and/or anticipated levels of intermittent renewable resources on each island system, that there may be technical and/or operational constraints upon the amount of additional intermittent renewable energy that each island system can absorb? If not, please discuss why not.

RESPONSE:

Yes, which has resulted in the Section 18 of the HCEI Energy Agreement Page 27, which the parties agreed to address technical and/or operational constraints. Section 18 states, inter alia:

Distributed Generation (DG) and Distributed Energy Storage (DES)

Distributed generation, including biofueled and fossil facilities, combined heat and power, and small renewable technologies such as wind and photovoltaics, can help replace central station generation and improve local grid operations and reliability. Similarly, DES (such as batteries, ice storage systems, flywheels and super-capacitors) can aid in firming intermittent renewables and provide load shifting and peak-shaving capabilities. To support and accelerate the adoption of DG and DES (termed broadly, distributed energy resources), the parties agree to the following:

> 1. The **Hawaiian Electric Companies will facilitate** planning for distributed energy resources through the Clean Energy Scenario Planning process and Locational Value Maps, to identify areas where these resources have system benefits and can be reasonably accommodated. The Locational Value Maps will be completed and become publicly available by December 31, 2009.
>
> 2. **The utilities will support non-utility DG and DES by improving the process and procedure for interconnecting non-utility DG and DES to make it faster, efficient, and more transparent. By June 30, 2009, the Hawaiian Electric utilities will submit a review of the implementation of the Rule l4H tariffs, as amended in May, 2008**.
>
> . . .
>
> 6. To the degree that **transmission and distribution automation and other smart grid technology investments are needed to facilitate distributed energy** resource utilization, **those investments will be recovered through the Clean Energy Infrastructure Surcharge** and later placed in rate base in the next rate case proceeding.
>
> . . .
>
> 9. In order to accept higher levels of DG on the utility grid, significant investment in smart grid technologies and changes in grid operations may be needed. These investments, if demonstrated to be prudent and reasonable, will be recovered through the Clean Energy Infrastructure Surcharge or through the general rate case recovery process. *(Emphasis added.)*

HECO/HSEA-IR-4
How does your FIT proposal insure that reliability and power quality on each island electric system are maintained?

RESPONSE:

PV invertors positively contribute to the feeder voltage regulation and result in an improved voltage profile. At a high enough penetration, PV invertors may be able to provide feeder voltage support. (Additional studies are needed on penetration which will be conducted pursuant to the Hawaii Clean Energy Initiative.) *See,* Distribution System Voltage Performance Analysis for High-Penetration Photovoltaics. NREL/SR-581-42298, February 2008.

HECO/HSEA-IR-5

What specific data, evaluations, studies or analyses did you rely upon as a part of any conclusion that your FIT proposal insures reliability on each island system? Please provide that data, evaluations, studies and/or analyses to the extent they are available.

RESPONSE:

- Distribution System Voltage Performance Analysis for High-Penetration Photovoltaics. NREL/SR-581-42298, February 2008.
- HECO's Ramp Rate Performance Standard for Intermittent Generation on the HECO System, March 14, 2008 at 8-10.
- Big Island Energy Road Map – Status, Terry Surles, Hawaii Natural Energy Institute, October 17, 2007.
- Technology Issues in Renewable Energy and Energy Efficiency, presented to the Hawaii State Legislature by Richard Rocheleau, Hawaii Natural Energy Institute, January 22, 2009.

HECO/HSEA-IR-6
As variable generation is presently having an adverse impact on a system's reliability, how would your FIT proposal mitigate any further adverse impacts?

RESPONSE:

HSEA does not agree with the assumption posed in this question that "As variable generation is presently having an adverse impact on a system's reliability". As discussed in our response to HECO/HSEA-IR-3, the utility has agreed to facilitate the acceptance of higher levels of DG on the utility grid. See also, our response to HECO/HSEA IR-4 and 5 in support of the proposition that PV has a positive impact on the utility system's reliability.

HSEA also notes that: (i) it is not clear to which "system" the question refers to and (ii) what the term "system" means in this context (*i.e.*, grid vs. circuit vs. other). Additionally, HSEA notes that to the extent that "variable generation is presently having an adverse impact on a system's reliability," the question is not phrased in a way that makes it possible for HSEA to know whether or not its expertise in solar PV is relevant, given that different forms of variable generation have different relationships with load.

HECO/HSEA-IR-7
Do you agree that your FIT proposal could result in increases in the rates paid by utility ratepayers? If so, what do you view as an acceptable level of increase for each of the utility system's ratepayers? What do you base that opinion on? Please provide any evaluations or analyses or studies used to support this opinion.

RESPONSE:

No, HSEA does not agree that its FIT proposal could result in increases in the rates paid by the utility ratepayers. The utility ratepayers may experience an increase in the short-run, but in the long-run (the 20 year term of the FIT contract) the utility ratepayer will experience: (i) stable and set rates; (ii) a decrease in rates, especially if the price of oil keeps rising in the next 20 years; and (iii) economic growth generally because the use of PV will create a "green" industry in the State of Hawaii, thus creating job opportunities in Hawaii and reducing the amount of dollars exported from the state to purchase fossil fuels. Based on the following assumptions:

Hypothertical System Size/Cost/Production

System Size kW	Sun Hours	Deerate	First year Annual kWh	20 year total kWh
10	5.4	0.77	15,177	303,269
100	5.4	0.77	151,767	3,032,686
500	5.4	0.77	758,835	15,163,431
1000	5.4	0.77	1,517,670	30,326,863

"Business as usual" cost of energy was based on 2007 Average Electric Rates for the HECO website. This rate was escalated at 6.5% per year over the 20 life of the FiT contract. Business as usual does not include potential significant lumpy increases due to Decoupling, CEIS, i.e. underwater sea cable, smart grid, etc.....

All the systems are installed in January 1, 2010.

The projected kWh and the projected cents per KWH were multiplied to derive the $ dollar value of the energy produce per year.

Transmission and distribution cost/changes are not considered factors since the Utility will recover these costs via the CEIS and Decoupling.

The result:

Utility	Rate Class	Year the Fit energy cost falls below the utiliy cost	Number of years that FiT Energy cost falls below the utiliy cost
HECO	Residntl	2020	10

	G rate	2019	11
	J Rate	2020	10
	P rate	2020	10
MECO	Residntl	2017	13
	G rate	2015	15
	J Rate	2015	15
	P rate	2015	15
Molokai	Residntl	2016	14
	G rate	2011	19
	J Rate	2013	17
	P rate	2014	16
Lanai	Residntl	2017	13
	G rate	2013	17
	J Rate	2012	18
	P rate	2013	17
HELCO	Residntl	2015	15
	G rate	2012	18
	J Rate	2014	16
	P rate	2014	16

Over the life of the 20 Year FIT agreement all the rate classes would experience a reduced cost of energy versus the utility business as usual cost of energy.

(Workpapers are available upon release.)

HECO/HSEA-IR-8

How does your FIT proposal insure that ratepayers within each of the three utility service territories do not receive significant rate increases?

RESPONSE;

See Response to HECO/HSEA-IR-7.

HECO/HSEA-IR-9

What specific data, evaluations, studies or analyses did you rely upon as a part of any conclusion that your FIT proposal insures that ratepayers within each of the three utility service territories do not receive significant rate increases? Please provide that data, evaluations, studies and/or analyses to the extent they are available.

RESPONSE;

See HSEA's Exhibit to HECO/HSEA-IR-5 and 7.

HECO/HSEA-IR-10

Do you agree that competitive bidding can provide benefits to ratepayers? If so, how does your proposal insure that ratepayers receive the benefits that competitive bidding can provide?

RESPONSE;

HSEA cannot take a position on this issue as no solar PV projects have been interconnected via the competitive bidding process.

HECO/HSEA-IR-11
Please explain why a feed in tariff should be applied to larger resources, rather than competitively bid to assure ratepayers the lowest prices for significant blocks of renewable energy?

RESPONSE:

HSEA notes again that no solar PV projects have been interconnected under the competitive bidding process. It is therefore not clear that competitive bidding would deliver solar energy to ratepayers.

In order to meet the penetration goals of the Hawaii Clean Energy Initiative feed in tariffs must be applied to larger resources because they eliminate the price/award uncertainty of competitive bidding. Relative to competitive bidding, FiT will encourage more PV developers into the market by providing them with a set price, while the uncertainty in competitive bidding raises the cost of capital for the developer and thus the ultimate price to the ratepayer.

HECO/HSEA-IR-12

Do you agree that if a Renewable Energy Generating Facility is unable to meet the technical requirements set forth in the utilities' rules relating to interconnection with the utility's electric system, that Renewable Energy Generating Facility should not be interconnected with the utility's electric system? If not, please discuss why not.

RESPONSE:

Yes, as long as the interconnection rules and requirements are applying best practices; i.e. Interstate Renewable Energy Council's Model Interconnection Standards and Procedures for Small Generator Facilities.

HECO/HSEA-IR-13
Do you agree that, as an electric system must remain in balance, if there is a greater amount of energy being generated in relation to load being served that generation must be reduced or curtailed to achieve system balance (assuming that load cannot be increased)? If not, please describe how the system balance can otherwise be achieved.

RESPONSE:

Yes.

HECO/HSEA-IR-14

Please explain how your proposal to require the utility to take all renewable energy generated by a FIT resource regardless of system need assures system balance and stability?

RESPONSE:

HSEA's proposal does not require the utility to take all renewable energy generated by a FIT resource regardless of system need assures system balance and stability. The HSEA proposal does require the utility to pay for all renewable energy generated by a FIT resource regardless of system need assures system balance and stability.

HECO/HSEA-IR-15

Is it your position that FIT resources may not be curtailed under any circumstance? If there are circumstances under which a FIT resource may be curtailed, please explain in detail how that curtailment would be accomplished. Please explain in detail how existing renewable projects fit into any curtailment order and the basis for assigning a lower curtailment priority to existing renewable resources.

RESPONSE:

No.

It is the utilities' decision as to how curtailments will be accomplished. To the extent that curtailment will be based upon the economics of the utilities, HSEA assumes that the utilities will take into account that under HSEA's proposal FIT generators will be paid even if they are curtailed.

HSEA's proposal does not assign a lower curtailment priority to existing renewable resources.

HECO/HSEA-IR-16

Please provide any evaluations, studies or analyses to support the following in your FIT proposal: (1) the inclusion of each renewable resource type; (2) the viability of each renewable resource type for each island system; (3) the project size demarcations for each renewable resource type; (4) the viability of each project size for each island system; and (5) the basis for a different or separate rate for each size demarcation (if applicable). This should include any information or evidence that you may have on the general or specific plans of any renewable resource developer to develop renewable resources of this type, and including the anticipated size of the project, on any island system within the next one, three and five years.

RESPONSE:

Please see response to HECO/HSEA-IR-5.

HSEA objects to the request for "any information or evidence that you may have on general or specific plans of any renewable resource developer to develop renewable resources of this type, and including the anticipated size of the project, on any island system within the next one, three and five years" because it calls for confidential, proprietary, and trade secret information from its members.

HECO/HSEA-IR-17

Please describe the methodology and rationale used to determine the proposed twenty (20) year terms in your FIT proposal for each technology. Please provide any evaluations, studies or analyses to support the proposed 20 years terms for each technology listed.

RESPONSE:

The proposed twenty (20) year term for PV came from HECO/CA's proposed FIT tariff sheets. Additionally, the 20 year term was used by HECO in its 100MW RFP and the State Department of Transportation in its RFP.

HECO/HSEA-IR-18

Please provide the bases for the proposed penetration limits for intermittent renewable energy sources. Please provide any evaluations, studies or analyses to support the proposed penetration limits, including in particular any evaluations, studies or analyses regarding maintenance of system reliability at the proposed penetration limits.

RESPONSE;

- *See,* Distribution System Voltage Performance Analysis for High-Penetration Photovoltaics. NREL/SR-581-42298, February 2008.

HECO/HSEA-IR-19

Please explain in detail how the proposed queuing procedures based upon those procedures proposed by the Midwest ISO would operate and be implemented for each island electric system. In particular, please provide any evaluations, studies or analyses of potential differences between the Midwest ISO service territory and the Hawaii utility electric systems and how those differences would be accommodated and addressed through your FIT proposal. Please discuss in detail whether the quality of power (steadiness, predictability, ability to enhance regulating resources on the grid and other such characteristic that are important to power reliability) should be a factor in setting the priority a project receives, and if not, why not.

RESPONSE:

The Midwest ISO queuing procedure[1] could operate and be implemented for each island electric system without significant modification.

Power quality and power reliability are factors affecting whether a project meets the utility's technical requirements for interconnection and, therefore, whether it is "ready-to-interconnect," but should not themselves be a factor in determining the priority that a project receives under the utility's queue management procedure for interconnection.

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[1] *See* Midwest Independent Transmission System Operator ("Midwest ISO"), Generator Interconnection Process Tariff (August 25, 2008) http://www.midwestmarket.org/publish/Document/ 25f0a7_11c1022c619_-7d600a48324a/Attachment%20X%20GIP.pdf?action=download&_property =Attachment; Midwest ISO, Business Practices Manual: Generator Interconnection (Manual No. 15, TP-BPM-004-r2, January 6, 200p) http://www.midwestmarket.org/publish/Document/45e84c_11cdc615aa1_-7e010a48324a ; 124 FERC ¶ 61,183, Midwest Independent Transmission System Operator, Inc., Docket No. ER08-1169-000, Order Conditionally Accepting Tariff Revisions and Addressing Queue Reform (August 25, 2008) http://elibrary.ferc.gov/idmws/doc_info.asp?document_id=13641108; Working group for Investment in Reliable & Economic electric Systems (WIRES), Integrating Locationally-Constrained Resources Into Transmission Systems: A Survey of U.S. Practices (October 2008) http://www.wiresgroup.com/images/WIRES_Report_LCR.pdf

HECO/HSEA-IR-20

Should a utility be entitled to use the generated output of a renewable resource in its service territory toward meeting a state or county mandated RPS standard regardless of ownership of the environmental credits? If not, please discuss why not?

RESPONSE:

HSEA is not the governing body to determine entitlement of the generated output of a renewable resource toward the mandated RPS. However, it should be noted that the FIT proposed by HSEA will provide a lower cost of energy generation to the utility, compared to "business as usual cost" (HECO/HSEA-IR-7) over the life of the agreement, (20 years), and thus the proposed PV FIT rates do not include compensation for the RECs.

HECO/HSEA-IR-21
Please provide any evaluations, studies, analyses or data to support the rates contained in your FIT proposal including detailed support for the applicability of those rates to the specified resources on the Hawaii utilities' island systems.

RESPONSE:

SA proposed FIT rates are based on investor/financier's acceptance of FiT rates that would result in an 20 year commitment. There has been discussions/question regarding the cost plus + reasonable profit as a method, but at the end of the day, the FIT rates needs to be at a level that will trigger the investment. The State of Hawaii recently executed power purchase agreements for ten sites across the State on three islands. The investor was able to commit to these rates without utilizing the State's REITC. See table below

Executed Third Party Financed PV Projects (No State Tax Credit)					[illegible]					
Location	PV System Size	Baseline rate $/kWh	Annual Escalation	Average Rate over 20 years	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Kauai- Ariport	154	0.38	2%	0.4617	100 to 500	$ 0.396	$ 0.436	$ 0.475	$ 0.475	$ 0.444
Kauai- Ariport	112	0.38	2%	0.4617	100 to 500	$ 0.396	$ 0.436	$ 0.475	$ 0.475	$ 0.444
Kauai- Ariport	35	0.38	2%	0.4617	11 to 100	$ 0.436	$ 0.479	$ 0.523	$ 0.523	$ 0.488
Kauai- Ariport	35	0.38	2%	0.4617	11 to 100	$ 0.436	$ 0.479	$ 0.523	$ 0.523	$ 0.488
Kaua -Highways	98	0.38	2%	0.4617	11 to 100	$ 0.436	$ 0.479	$ 0.523	$ 0.523	$ 0.488
Kauai - Harbors	30	0.38	2%	0.4617	11 to 100	$ 0.436	$ 0.479	$ 0.523	$ 0.523	$ 0.488
Hilo Airport	112	0.33	3%	0.4434	100 to 500	$ 0.396	$ 0.436	$ 0.475	$ 0.475	$ 0.444
Kona Airport	60	0.32	3%	0.4299	11 to 100	$ 0.436	$ 0.479	$ 0.523	$ 0.523	$ 0.488
Kahului - Airport	112	0.32	3%	0.4299	100 to 500	$ 0.396	$ 0.436	$ 0.475	$ 0.475	$ 0.444
Kahului - Airport	31	0.32	3%	0.4299	11 to 100	$ 0.436	$ 0.479	$ 0.523	$ 0.523	$ 0.488

SA's proposed FiT rates is levelized for 20 twenty years with no escalation. The third party financed rates start lower and escalate over the life of the agreement. In order to provide sum degree of comparison, the "Average Rate over 20 years" column reflects the average of the escalated rates for twenty year. The green labeled section is the proposed FiT rates for the relative system size. The proposed SA FiT rates is definitely within reason, (some above/some below) the third party financed contracts that the State of Hawaii signed.

Also in support of HSES's proposed FIT rates is the following article:

Ontario Proposes Precedent-Setting Renewable Tariffs

World Class Solar Tariffs for North America
March 12, 2009

By Paul Gipe

(Toronto, Ontario) Ontario's Minister of Energy and Infrastructure, George Smitherman, announced today that the Ontario Power Authority (OPA) will be establishing a system of feed-in tariffs as a result of the pending Green Energy and

Green Economy Act.

Minister Smitherman also released OPA's proposed tariffs for a host of renewable energy technologies.

If implemented, the package of tariffs will represent the first application of Advanced Renewable Tariffs in North America. The system of feed-in tariffs envisioned by Minister Smitherman is a Canadian version of the successful policies used in Germany, France, Spain, and several other European countries.

OPA will begin public consultation on the tariffs and elements of the program March 17th and will continue hearings for the next seven weeks.

The tariffs are precedent setting in North America not only for the number of different technologies listed, including offshore wind, but also for the prices offered.

Solar energy advocates will be particularly pleased. Ontario's proposed tariffs, if implemented, will be the highest in North America. For rooftop solar they will be comparable to those offered in Germany and France. On the other hand, Ontario's proposed tariffs for ground-mounted systems will be less than those in Germany, a country with a comparable solar resource.

OPA's press release suggested that the tariff for residential rooftop solar PV could result in 100,000 solar installations capable of generating one percent of Ontario's electricity supply. One percent of Ontario's supply is 1.5 TWh or nearly one-third the 2008 solar generation in Germany, the world's leader in solar energy.

Similarly, the tariffs for biogas plants will be among the highest, if not the highest on the continent. Unlike higher tariffs offered by some utilities in Wisconsin, Ontario's proposed tariffs are for 20-year contracts. The tariffs offered in Wisconsin are paid only for ten years.

The wind tariffs proposed are less robust than expected. The tariffs for onshore wind are nearly identical to those proposed by the Ontario Sustainable Energy Association in 2005. Since that time, the installed cost of wind turbines has increased substantially.

The proposed wind tariffs are comparable to those in France, but substantially less than those in Germany. And unlike in Germany and France, the tariffs are not differentiated by resource intensity.

OPA proposes two wind tariffs, one for community wind projects, another tariff for everything else. OPA does not differentiate the tariffs further.

In another first in North America, OPA has proposed a specific tariff for offshore wind. Ontario fronts four of the Great Lakes: Superior, Huron, Erie, and Ontario. Consequently, Ontario has a huge offshore wind resource.

Currently, there are no wind turbines in any of the Great Lakes, though there are several proposals for projects in waters off Ontario.

The tariffs proposed by OPA represent the total payment for renewable energy. There are no federal or provincial subsidies for renewable electricity generation in Ontario.

While several US states have rudimentary feed-in tariffs, often with contracts of limited length, no US state has as comprehensive a system of feed-in tariffs as that proposed by OPA. Nor does any state in the US pay as high tariffs as those proposed in Ontario, in part because of lucrative US federal tax subsidies.

Ontario Ministry of Energy's Proposed Renewable Energy Tariffs
2009

12-Mar-09

		1.649		0.777
	Years	€/kWh	$CAD/kWh	USD/kWh
Wind				
Onshore	20	0.0819	0.135	0.105
Offshore	20	0.1152	0.190	0.148
Community-based <10 MW	20	0.0873	0.144	0.112
Photovoltaics				
Rooftop <10 kW	20	0.4864	0.802	0.623
Rooftop >10 kW<100 kW	20	0.4325	0.713	0.554
Rooftop >100 kW<500 kW	20	0.3851	0.635	0.494
Rooftop >500 kW	20	0.3269	0.539	0.419
Groundmounted <10 MW	20	0.2687	0.443	0.344
Hydro				
<50 MW	20	0.0782	0.129	0.100
Community-based <2 MW	20	0.0813	0.134	0.104
Landfill Gas				
<5 MW	20	0.0673	0.111	0.086
>5 MW	20	0.0625	0.103	0.080
Biogas				
<5 MW	20	0.0892	0.147	0.114
>5 MW	20	0.0631	0.104	0.081
Biomass				
Any size	20	0.0740	0.122	0.095

HECO/HSEA-IR-22
Please explain how your proposed rates are affected by the key costs and operating characteristics referenced in the Commission's NRRI Scoping Paper filed December 11, 2008.

RESPONSE:

The key costs and operating characterics referenced in the Commission's NRRI Scoping Paper were taken into consideration in establishing SA's proposed rates. However, the factor that had the most significant was what rate would encourage investors to invest in PV energy in Hawaii.

HECO/HSEA-IR-23 Ref: Issue 3

Please describe in detail your statement that a PBFit is not necessarily a superior mechanism for certain technologies including identification of the technologies and the specific reasons why a PBFit is not a superior mechanism for those technologies.

RESPONSE:

HSEA's response to Issue No. 3 was intended to convey the fact that HSEA can offer only limited insight into the extent to which a "PBFiT is the superior methodology to meet Hawaii's clean energy and energy independence goals" for some technologies because knowing which mechanism is superior would require an awareness of factors - such as financing terms, sources of risk, and rates of return – that HSEA does not have access to for some technologies.

HECO/HSEA-IR-24 Ref: Issue 3

Please describe in detail all impediments to potential investors achieving a sufficient risk adjusted rate of return on solar projects in the State of Hawaii

RESPONSE:

The primary impediment to potential investors achieving a sufficient risk adjusted rate of return on solar projects in the State of Hawaii is the lack of functioning a state level incentive. Additionally, in a subset of situations, the following other factors are involved: net energy metering limit of 100 kW per system, length of time and unknown result of IRS study, length Interconnection negotiations, and land use approval, permitting (length of time).

HECO/HSEA-IR-25

Please explain how your proposed rates are affected by the key costs and operating characteristics referenced in the Commission's NRRI Scoping Paper filed December 11, 2008.

RESPONSE:

The costs and operating characteristics are embedded in the rates proposed by HSEA, because these rates reflect marketplace realities in the absence of a feed-in tariff.

HECO/HSEA-IR-26

Please provide any evaluations, studies, or analysis to support modifying Rule 14H, such that the penetration level at which an interconnection study is required is increased from 10% to 15%, to ensure that other customers on the distribution circuit are not adversely affected during islanding or disturbance conditions.

RESPONSE:

As noted in HSEA's Opening Statement of Position with Respect to Issue #4, its suggestion of an increase from 10 to 15 percent is based on the level proposed in the Energy Agreement signed by the State and the HECO Companies. Section 19, Net Energy Metering, notes that "Distributed generation interconnection will be limited on a per-circuit basis, where generation (including PV, micro wind, internal combustion engines, and net metered generation) feeding into the circuit shall be limited to no more than 15% of peak circuit demand for all distribution-level circuits of 12kV or lower;" and "For those circuits where interconnection requests (particularly for PV) approach the 15% limit, the utility will perform and complete within 60-days after receipt of an interconnection request, a circuit-specific analysis to determine whether the limit can be increased." HSEA believed that, taken together, these two statements indicated a comfort level with 15 percent DG interconnection given current technology, with the potential for higher levels in response to grid upgrades. In addition, HSEA notes that evidence regarding the usefulness of the 10 percent threshold of the interconnection study is currently being amassed by the HECO companies via the IRS studies they have currently required of some developers.

HECO/HSEA-IR-27

Please explain how system monitoring and control of projects connected via the FIT can be achieved, if the requirement for SCADA interface is removed? Does HSEA believe that penetrations of solar energy should be limited to the levels that can be achieved without negative impact on reliability given currently standard component on solar projects, or does it support enhancing the capabilities of solar projects in order to achieve a greater overall percentage?

RESPONSE:

HSEA was unable to determine which of its responses is referred to by HECO/HSEA-IR-27. Without context for the question HSEA finds it impossible to formulate an answer.

HECO/HSEA-IR-28

If entities are compensated for curtailment, and given that the HSEA does not support caps, what mechanism would be enacted to avoid connecting projects which far exceed the system demand so that the system is unable to take the energy, resulting in excessive rate increases in order to compensate for non-production?

RESPONSE:

Given the rapid development of grid infrastructure technology and the utility's proposed movement to "smarten" the grid, HSEA does not believe that it is appropriate to speculate on what the appropriate answer will be given the state of grid infrastructure, storage, and technology development at the time when projects that "far exceed the system demand" are proposed for interconnection.

HECO/HSEA-IR-29

Given that HSEA does not support caps, what mechanism will be utilized to ensure the necessary infrastructure and mix of generation resources to provide transfer capability, system frequency control, load following, voltage control, and system stability through faults?

RESPONSE:

HSEA believes that the choice of infrastructure to address grid stability and reliability concerns will ultimately be determined by the utility under direction from the Commission. HSEA believes that whatever mechanism chosen should be selected based on its ability to ensure that the greatest level of renewable penetration is achieved.

DBEDT-IR-1-HSEA: Ref. Schedule FIT, Pages 4-9.

Please provide all the workpapers and data used to determine the proposed feed-in tariff rates in the referenced pages.

RESPONSE:

Riley to draft response.

CERTIFICATE OF SERVICE

The foregoing Responses to Information Requests were served on the date of filing by hand delivery or electronically transmitted to the following Parties:

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DATED: Honolulu, Hawaii, March 13 2009.

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